APPENDIX A

TO FIRST REVISED CONSENT DECREE

MAP's List of Flaring Devices

FIRST REVISED CONSENT DECREE

APPENDIX A

MAP'S LIST OF FLARING DEVICES

A. ACID GAS FLARING DEVICES

CANTON

North Flare

CATLETTSBURG

North Area Flare (2-FS-11-1)

DETROIT

Unifiner Flare (0029)

Cracking Plant Flare (0031)

GARYVILLE

South Flare (69-74)

North Flare (83-74)

ROBINSON

Flare Number #1 -- #6 (84-F-1 through 6)

ST. PAUL PARK

Main Flare (CE005)

B. HYDROCARBON FLARING DEVICES

CANTON

South Flare

North Flare

CATLETTSBURG

Pitch Flare (1-14-FS-3)

Lube Petrochem Flare (1-14-FS-2)

South Area Flare (2-11-FS-1)

New North Area Flare (2-11-FS-2)

HF Alkylation Flare (2-11-FS-3)

RCCS Flare (2-11-FS-4)

DETROIT

Unifiner Flare (0029)

Cracking Plant Flare (0031)

Crude Flare (0036)

Alkylation Flare (0030)

GARYVILLE

South Flare (69-74)

North Flare (83-74)

Refrigerated Butane Storage Flare

Marine Vapor Combustor

ROBINSON

Flare # 1 (84-F-1)

Flare # 2 (84-F-2)

Flare # 3 (84-F-3)

Flare # 4 (84-F-4)

Flare # 5 (84-F-5)

Flare # 6 (84-F-6)

Wastewater Treatment Flare (84-F-7)

ST. PAUL PARK

Main Flare (CE005)

Loading Rack Flare (used when Condenser is out-of-service)

TEXAS CITY

Main Flare (ES60)

Alkylation Flare (ES16)

WWTP Flare

Benzene Loading Combustor Flare

APPENDIX B

TO FIRST REVISED CONSENT DECREE

[OMITTED]

APPENDIX C

TO FIRST REVISED CONSENT DECREE

1999-2000 Actual Heater and Boiler Nox Emissions by Unit

SUMMARY OF NOx EMISSIONS - MAP REFINERIES

Appendix C

Emission Source Category	Operating Year 1999		Operating Year 2000		Avg. 1999/2000	
	Actual Firing Rate MM BTU/hr (hhv)	NOx Emissions (tpy)	Actual Firing Rate MM BTU/hr (hhv)	NOx Emissions (tpy)	Actual Firing Rate MM BTU/hr (hhv)	NOx Emissions (tpy)
Process Heaters/Boilers (> 40 MM BTU/hr)						
Canton	576	551	671	534	624	542
Catlettsburg	2,622	1,821	2,573	1,818	2,598	1,820
Detroit	517	372	528	378	522	375
Garyville	2,970	2,163	2,852	2,030	2,911	2,097
Robinson	2,576	1,384	2,395	1,361	2,485	1,373
St. Paul Park	688	428	737	459	713	444
Texas City	700	338	638	301	669	320
Subtotal	10,649	7,058	10,395	6,884	10,522	6,971
Gas-Fired Reciprocating Compressors						
Texas City (4 FCC Wet Gas)	188	373	172	342	180	358
Texas City (2 Hydrogen)	65	145	108	231	86	188
Detroit (4 FCC Wet Gas)	75	247	69	186	72	217
Subtotal	328	765	172	759	338	762
Baseline Totals (Heaters, Boilers, & Gas-Fired Compressors)						
Values for Sigma Equation	10,977	7,823	10,566	7,643	10,860	7,733
HEATERS/BOILERS (<40 MM BTU/HR) & OTHER MISCELLANEOUS SOURCES						
Canton	18	9	20	8	19	8
Catlettsburg	161	61	165	63	163	62
Detroit	57	151	58	151	58	151
Garyville	23.2	12	27	14	25	13
Robinson	130	53	109	45	119	49
St. Paul Park	102	36	96	39	99	37
Texas City	34	15	32	14	33	14
Subtotal	526	336	506	334	516	335

SUMMARY OF HEATING VALUES FOR FUEL GAS - MAP REFINERIES

	MAP REFINERY	Higher Heating Value of Fuel Gas (BTU/Standard Cubic Foot) Operating Year	
		1999	**2000**
	Canton		
1	North Drum	666	782
2	South Drum	941	1,119
	Catlettsburg		
3	Pitch Fuel Gas Drum	1,133	1,110
4	Petrochemical Area Drum	1,200	1,172
5	Lube Fuel Gas Drum	992	1,024
6	NASA Fuel Gas Drum	981	1,034
5	RCC Fuel Gas Drum	904	953
	Detroit		
6	Crude Alcorn Fuel Gas Drum	1,004	1,049
7	Unifiner Fuel Gas Drum	972	1,123
8	SR Platformer Fuel Gas Drum	1,004	1,010
	Garyville		
9	Fuel Gas	932	954
10	Natural Gas	1,030	1,030
	Robinson		
11	Ultraformer Fuel Drum	1,036	889
12	Crude Unit Fuel Drum	1,151	1,086
13	Ultrafiner Fuel Drum	657	619
14	Unicracker Fuel Drum	1,160	1,160
15	Platformer Fuel Drum	1,175	1,047
16	Alkylation Fuel Drum	1,147	1,186
17	Boiler Fuel Drum	1,129	1,136
18	Special Coker Fuel Drum	1,029	1,029
19	Natural Gas	N/A	N/A
	St. Paul Park		
20	Fuel Gas Drum	1,025	1,068
21	Purchased Natural Gas	981	985
22	Hydrogen Gas	268	330
	Texas City		
23	Fuel Gas Drum	950	1000
24	Natural Gas	1030	1050

PROCESS HEATERS/BOILERS AT CANTON, OH REFINERY

Emission Source	Design Firing Rate MM BTU/hr (hhv)	Operating Year 1999 Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Operating Year 1999 Firing Rate (MM BTU/hr) - hhv	Operating Year 1999 Emission Factor (lb/MM scf) - gas (lb/1000 gal) - oil	Operating Year 1999 Nox Emissions (tpy)	Operating Year 2000 Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Operating Year 2000 Firing Rate (MM BTU/hr) -hhv	Operating Year 2000 Emission Factor (lb/MM scf) - gas (lb/1000 gal) - oil	Operating Year 2000 Nox Emissions (tpy)	Basis for Emission Factor
HEATERS/BOILRERS (>100 MM BTU/HR)										
CCR Charge Heaters (4-33-B-1,2, 3, & 4)	242	1,506	114	280	211	1,436	128	280	201	AP-42 - 280 lb/MM scf
Crude Heater (4-0-B-6)	193	852	91	280	119	919	117	280	129	AP-42 - 280 lb/MM scf
Number 11 Boiler (4-16-B-11)										
fuel gas	176	416	45	0.17 lb/MM BTU	70	445	57	0.17 lb/MM BTU	77	NOx CEM Data
fuel oil		69,200	50			65,091	47			
Subtotal (> 100 MM BTU/hr)										
fuel gas	611	2,774	251	289	400	2,800	302	291	407	
fuel oil		69,200	50	47		65,091	47	47		
HEATERS/BOILRERS (>40 MM BTU/HR & <100 MM BTU/HR)										
HDS Charge Heater (4-32-B-1)										
fuel gas	94	426	46	100	21	415	53	100	21	AP-42 - 100 lb/MM scf
fuel oil		8,487	6	47	8	9,216	7	47	9	AP-42 - 47 lb/1000 gallons
Naphtha Pretreater (4-30-B-1)	83	242	33	100	12	209	28	100	10	AP-42 - 100 lb/MM scf
CCR Stabilizer Reboiler (4-33-B-5)	43	144	11	100	7	146	13	100	7	AP-42 - 100 lb/MM scf
Vacuum Heater (4-4-B-1)	64	371	40	100	19	431	55	100	22	AP-42 - 100 lb/MM scf
Number 12 Boiler (4-16-B-12)	81	283	30	100	14	229	29	100	11	AP-42 - 100 lb/MM scf
Number 1 Boiler (4-16-B-1)										
fuel gas	55	148	16	100	7	80	10	100	4	AP-42 - 100 lb/MM scf
fuel oil		1,586	1	47	2	2,188	2	47	2	AP-42 - 47 lb/1000 gallons
Number 2 Boiler (4-16-B-2)										
fuel gas	55	110	12	100	6	131	17	100	7	AP-42 - 100 lb/MM scf
fuel oil		1,388	1	47	1	4,548	3	47	4	AP-42 - 47 lb/1000 gallons
FCC Charge Heater (4-2-B-6)	51	187	20	100	9	303	39	100	15	AP-42 - 100 lb/MM scf
Iso-Stripper Heater (4-27-B-1)	50	281	30	100	14	280.5	36	100	14	AP-42 - 100 lb/MM scf
Subtotal (>40 & <100 MM BTU/hr)										
fuel gas	576	10,700	265	26	139	11,461	307	19	111	
fuel oil		2,982	11	47	11	6,745	14	47	16	
Heaters/Boilers (Applied Towards Sigma Equation)										
fuel gas	**1,187**	**13,474**	**516**	**80**	**540**	**14,261**	**610**	**73**	**518**	
fuel oil		**72,182**	**60**	**47**	**11**	**71,836**	**61**	**47**	**16**	
Overall	**1,187**		**576**		**551**		**671**		**534**	
HEATERS/BOILERS (<40 MM BTU/HR)										
DOT HEATER (4-2-B-1)	39	170	18	100	9	160.1	20	100	8	AP-42 - 100 lb/MM scf

PROCESS HEATERS BOILERS AT CATLETTSBURG, KY REFINERY

Emission Source	Design Firing Rate	Operating Year 1999				Operating Year 2000				Basis for Emission Factor
	MM BTU/hr (hhv)	Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Firing Rate MM BTU/hr (hhv)	Emission Factor (lb/MM BTU) - gas (lb/1000 gal) - oil	Nox Emissions (tpy)	Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Firing Rate MM BTU/hr (hhv)	Emission Factor (lb/MM scf) - gas (lb/1000 gal) - oil	Nox Emissions (tpy)	
PROCESS HEATERS/BOILERS > 100 MM BTU/HR										
#5 Crude Charge Htr (1-41-B-1)										
Fuel Gas	330	1,689	190	0.09	91	1,499	172	0.09	87	Stack test 09/9/97 - avg 3 runs
Fuel Oil		57,810	41			68,602	49			
#4 Boiler (2-601-B-4)	325	1,519	170	0.14	104	1,361	157	0.14	96	NOx CEM Data - (2003 Ozone Season)
#12 Boiler (2-601-B-12)	206	1,051	117	0.12	61	988	114	0.12	60	NOx CEM Data - (Avg of 2002/2003 data)
SAT Gas Plant Htr (2-30-B-1)	178	923	103	0.27	129	832	96	0.27	116	AP-42 - 280 lbs/MM scf
#3 Crude Htr (2-23-B-3)										
Fuel Gas	177	1,116	125	0.27	156	1,153	133	0.27	161	AP-42 - 280 lbs/MM scf
Fuel Oil		11	0	47	0	0	0	0.00	0	AP-42 - 47 lbs/1000 gallons
#3 Crude Htr (2-23-B-4)										
Fuel Gas	177	1,051	117	0.27	147	1,153	133	0.27	161	AP-42 - 280 lbs/MM scf
Fuel Oil		11,194	8	47.00	11	0	0	0.00	0	AP-42 - 47 lbs/1000 gallons
CCR Htr (2-102-B-1B)	171	822	92	0.27	115	750	87	0.27	105	AP-42 - 280 lbs/MM scf
#10 Boiler (2-601-B-10)	162	434	49	0.16	34	327	38	0.16	27	Stack tested 12/10/02 -avg 3 runs
CCR Htr (2-102-B-1A)	160	816	91	0.27	114	796	92	0.27	111	AP-42 - 280 lbs/MM scf
#4 Vac Htr (2-26-B-2)	138	780	87	0.06	22	737	85	0.06	21	Stack test 05/30/97 - avg 3 runs
FCC Charge Htr (2-1-B-8)	160	411	46	0.27	58	564	65	0.27	79	AP-42 - 280 lbs/MM scf
#11 Boiler (1-39-B-1)	125	410	46	0.17	34	460	53	0.17	39	Stack Tested 12/12/02 - avg 3 runs
CCR Htr (2-102-B-1C)	123	574	64	0.27	80	716	83	0.27	100	AP-42 - 280 lbs/MM scf
VGO Charge Htr (2-104-B-1)	113	409	46	0.27	57	432	50	0.27	60	AP-42 - 280 lbs/MM scf
VGO Charge Htr (2-104-B-2)	113	444	50	0.27	62	468	54	0.27	66	AP-42 - 280 lbs/MM scf
#2 Crude Charge Htr (1-2-B-3)										
Fuel Gas	109	382	49	0.098	33	363	45	0.098	34	Stack Test on 07/17/02 - avg 3 runs
Fuel Oil		38,875	28			47,502	34			
Aliphatics Hot Oil Htr (1-4-B-6)	106	590	80	0.12	42	605	78	0.12	41	Stack Test on 07/18/02 - avg 3 runs
#5 Vac Rerun Htr (1-37-B-1)	105	777	88	0.26	100	709	81	0.26	92	Stack Test on 07/18/02 - avg 3 runs
Subtotal										
Fuel Gas	2,975	14,198	1,610	0.20	1,442	13,913	1,616	0.21	1,459	
Fuel Oil		107,890	8	0.31	11	0	0	0.00	0	
Process Heaters/Boilers (> 40 MM BTU/hr & < 100 MM BTU/hr)										
LPCCR No. 1 Interhtr (1-44-B-2)	99	438	60	0.045	12	462	60	0.045	12	Stack Test 01/9/97 - avg 3 runs
Isomerization Htrs (2-35-B-1 & 2)	99	326	36	0.12	19	346	40	0.12	21	Stack Test on 07/22/02 - avg 3 runs
HF Alky Isostripper Reboiler (2-36-B-1)	95	396	44	0.097	20	325	38	0.097	16	AP-42 - 100 lbs/MM scf
#2 DDS Stripper Reboiler (2-121-B-3)	94	423	47	0.02	5	447	52	0.02	5	Stack Test 01/8/97 - avg 3 runs
NPT Stripper Reboiler (2-101-B-2)	88	369	41	0.097	18	350	40	0.097	18	AP-42 - 100 lbs/MM scf
#7 Boiler (2-601-B-7)	78	321	44	0.085	16	346	45	0.085	17	AP-42 - 100 lbs/MM scf
#8 Boiler (2-601-B-8)	78	285	39	0.085	14	238	31	0.085	12	AP-42 - 100 lbs/MM scf
LPCCR Charge Htr (1-44-B-1)	77	401	54	0.045	11	418	54	0.045	11	Stack Test 01/9/97 - avg 3 runs
LPCCR No. 2 Interhtr (1-44-B-3)	77	261	35	0.045	7	279	36	0.045	7	Stack Test 01/9/97 - avg 3 runs
#5 Boiler (2-601-B-5)	76	257	29	0.097	13	260	30	0.097	13	AP-42 - 100 lbs/MM scf
#6 Boiler (2-601-B-6)	76	349	39	0.097	17	380	44	0.097	19	AP-42 - 100 lbs/MM scf
#1 Boiler (2-601-B-1)	75	141	16	0.097	7	15	2	0.097	1	AP-42 - 100 lbs/MM scf

PROCESS HEATERS BOILERS AT CATLETTSBURG, KY REFINERY

Emission Source	Design Firing Rate MM BTU/hr (hhv)	Operating Year 1999 Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Operating Year 1999 Firing Rate MM BTU/hr (hhv)	Operating Year 1999 Emission Factor (lb/MM BTU) - gas (lb/1000 gal) - oil	Operating Year 1999 Nox Emissions (tpy)	Operating Year 2000 Fuel Consumed (MM scf/yr) - gas (bbls/yr) - oil	Operating Year 2000 Firing Rate MM BTU/hr (hhv)	Operating Year 2000 Emission Factor (lb/MM scf) - gas (lb/1000 gal) - oil	Operating Year 2000 Nox Emissions (tpy)	Basis for Emission Factor
#1 Cumene Column Reboiler (1-35-B-3)	74	380	52	0.075	17	439	57	0.075	19	Stack Test -(01/15/98) - avg 3 runs
Furfural Htr (1-38-B-2)	72	438	49	0.097	22	397	46	0.097	20	Stack Test - (10/15/02)
Benzene Column Reboiler (1-35-B-1)	70	354	48	0.094	18	357	46	0.094	18	Stack test data - 09/23/02
SHU Hot Oil Htr (1-29-B-1)	69	222	30	0.085	11	139	0.00	0.085	7	AP-42 - 100 lbs/MM scf
SHU Reactor Htr (1-29-B-4)	69	124	17	0.085	6	126	16	0.085	6	AP-42 - 100 lbs/MM scf
NPT Charge Htr (2-101-B-1)	66	228	25	0.097	11	214	25	0.097	11	AP-42 - 100 lbs/MM scf
SPU Reactor Charge Htr (2-31-B-2)	65	60	7	0.097	3	136	8	0.097	7	AP-42 - 100 lbs/MM scf
ADS #2 Tower Reboiler (1-28-2)	62	72	10	0.085	4	105	13	0.085	5	AP-42 - 100 lbs/MM scf
LEP Unit Dehexanizer Reboiler (1-43-B-1)	62	435	49	0.097	22	396	45	0.097	20	Stack Test - (10/15/02)
#2 DDS Reactor Charge Htr (2-121-B-1)	61	109	12	0.037	2	140	16	0.037	3	Stack Test - (01/8/97) - Avg 3 runs
#2 DDS Reactor Charge Htr (2-121-B-2)	61	113	13	0.037	2	203	14	0.037	2	Stack Test - (01/8/97) - Avg 3 runs
LPCCR No. 3 Interhtr (1-44-B-4)	55	233	32	0.045	6	231	30	0.045	6	Stack Test - (01/9/97) - Avg 3 runs
DDS Stripper (2-103-B-3)	55	105	12	0.097	5	212	12	0.097	11	AP-42 - 100 lbs/MM scf
Spec G-Oil Charge Htr (1-25-B-1)	53	196	27	0.085	10	186	24	0.085	9	AP-42 - 100 lbs/MM scf
DDS Charge Htr (2-103-B-1)	50	63	9	0.097	3	68	8	0.097	3	AP-42 - 100 lbs/MM scf
DDS Charge Htr (2-103-B-2)	50	40	4	0.097	2	79	9	0.097	4	AP-42 - 100 lbs/MM scf
#2 Vacuum Charge Htr (1-2-B-1)										
Fuel Gas	50	147	19	0.258	27	131	16	0.258	18	AP-42 - 100 lbs/MM scf
Fuel Oil		6,579	5			0	0			AP-42 - 47 lbs/1000 gallons
LPCCR Guard Case Htrs (1-4-B-7)	46	249	34	0.085	12	286	37	0.085	14	AP-42 - 100 lbs/MM scf
LPCCR Guard Case Htrs (1-4-B-8)	46	242	33	0.085	12	220	28	0.085	11	AP-42 - 100 lbs/MM scf
Pitch Htr (1-3-B-1)	44	147	19	0.09	7	170	21	0.09	9	AP-42 - 100 lbs/MM scf
Fractionator Bottoms Htr (1-2-B-4)	43	108	14	0.1	6	110	14	0.1	6	AP-42 - 100 lbs/MM scf
Subtotal (>40 & < 100 MM BTU/hr)										
Fuel Gas	2,232	14,610	1,004	0.08	368	8,210	957	0.09	360	
Fuel Oil		0	0	0.00	0	0	0	0.00	0	
TOTALS (ALL HEATERS/BOILERS > 40 MM BTU/HR)										
Fuel Gas	5,208	28,808	2,614	0.16	1,810	22,123	2,573	0.16	1,818	
Fuel Oil		107,890	8	0.31	11	0	0	0.00	0	
OVERALL	5,208		2,622	0.16	1,821		2,573	0.16	1,818	
HEATERS/BOILERS (<40 MM BTU/HR)										
CCR Htr (2-102-B-1D)	39	101	10	0.1	4	67	7	0.1	3	AP-42 - 100 lbs/MM scf
Asphalt Mix Htr (2-31-B-1)	33	124	13	0.05	3	106	11	0.05	2	Stack Test (01/17/95) - Avg 3 runs
ADS Charge Htr (1-28-B-1)	30	130	15	0.1	7	136	16	0.1	7	AP-42 - 100 lbs/MM scf
CCR Debutanizer (2-102-B-2)	29	219	25	0.1	11	219	25	0.1	11	AP-42 - 100 lbs/MM scf
LPCCR Debutanizer Reboiler (1-44-B-5)	28	103	12	0.045	2	106	13	0.045	3	Stack Test (01/09/97) - Avg 3 runs
Furfural Htr (1-38-B-1)	24	122	13	0.1	6	112	12	0.1	5	AP-42 - 100 lbs/MM scf
Cumene Column Reboiler (1-35-B-2)	21	137	16	0.1	7	138	16	0.1	7	AP-42 - 100 lbs/MM scf
Asphalt Htr (1-6-B-1)	20	1.8	0.3	0.1	0	2	0	0.1	0	AP-42 - 100 lbs/MM scf
Asphalt Htr (1-6-B-2)	20	1.8	0.3	0.1	0	2	0	0.1	0	AP-42 - 100 lbs/MM scf
Oxidizer Fume Burner (1-6-B-6)	20	5.5	0.6	0.1	0	5	1	0.1	0	AP-42 - 100 lbs/MM scf
SHU/SPU Hot Oil Htr (1-29-B-2)	15	245	29	0.1	13	337	40	0.1	18	AP-42 - 100 lbs/MM scf
Road Oil Fume Burner (1-6-B-5)	13	0.0	0.0	0.1	0	0	0	0.1	0	AP-42 - 100 lbs/MM scf
SDA Hot Oil Htr (2-31-B-2)	12	244	25	0.06	7	203	22	0.06	6	Stack Test (01/17/95) - Avg 3 runs
Regenerant Vapor Superheater (2-35-B-3)	3	20	2	0.1	1	19	2	0.1	1	AP-42 - 100 lbs/MM scf
Subtotal (< 40 MM BTU/hr)	306	1,454	161	0.09	61	1,452	165	0.09	63	

PROCESS HEATERS AND BOILERS at DETROIT, MI REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr	MM BTU/hr (hhv)	lb/MM Btu	(tpy)	MMscf/yr	MM BTU/hr (hhv)	lb/MM Btu	(tpy)	
HEATERS & BOILERS (> 100 MM BTU/HR)										
Zurn Boiler (EU00159)	210	334	38	0.100	17	247	28	0.100	12	Avg. NOx Conc of 100 ppmv - CEM
Crude Alcorn Heater (EU0070)	200	1,449	166	0.265	193	1,374	165	0.265	191	Stack Test (03/27/97) - Avg. 3 runs (Common Stack with Vacuum Heater)
SR Platformer Charge Htr (EU00141)	130	631	72	0.043	14	524	60	0.043	11	Stack Test (12/17/92) - Avg 3 runs
FCCU Preheater (EU00109)	102	475	54	0.090	21	426	49	0.090	19	Stack Test 12/18/02 - Lan Com
Subtotal	642	2,889	331	0.169	245	2,571	302		234	
HEATERS & BOILERS (> 40 MM BTU/HR & < 100 MM BTU/HR)										
Crude Vacuum Heater (EU00066)	96	625	72	0.265	83	619	74	0.265	86	Stack Test (03/27/97) - Avg. 3 runs (Common Stack with Crude Heater)
G.O/Unifiner Charge Heater (EU00089)	75	186	21	0.041	4	244	31	0.041	6	Stack Test (06/07/94) - Avg. 3 runs
BT Interheater (EU00148)	65	222	25	0.100	11	422	49	0.100	21	AP-42 - 100 lbs/MM scf
BT Charge Heater (EU00147)	64	168	19	0.100	8	213	25	0.100	11	AP-42 - 100 lbs/MM scf
Alkylation Reboiler (EU0097)	53	248	28	0.100	12	195	25	0.100	11	AP-42 - 100 lbs/MM scf
NHT Charge Heater (EU00143)	40	186	21	0.100	9	191	22	0.100	10	AP-42 - 100 lbs/MM scf
Subtotal	393	1,635	186	0.157	128	1,884	226	0.146	144	
GAS FIRED RECIPROCATING COMPRESSORS										
FCC Air Blowers										
11C4	15 (440 BHP)	4368 hrs	5	8.4 lb/hr	18	2520 hrs	4	8.4 lb/hr	11	Stack Test on 05/22/99 - Avg of 3 runs
11C5	22 (660 BHP)	5232 hrs	10	8.4 lb/hr	22	1848 hrs	5	8.4 lb/hr	8	Emission factor from 11C4 compressor
11C6	50 (1500 BHP)	7440 hrs	30	27.2 lb/hr	101	6888 hrs	30	27.2 lb/hr	94	Emission factor from 11C7 compressor
11C7	50 (1500 BHP)	7776 hrs	30	27.2 lb/hr	106	5400 hrs	30	27.2 lb/hr	73	Stack Test on 05/22/99 - Avg of 3 runs
Total	137 (4100 BHP)		75		247		69		186	
BASELINE TOTALS (UTILIZED IN SIGMA EQUATION)										
Totals	1,172	4,524	592	0.239	619	4,455	597	0.216	564	
HEATERS/BOILERS (< 40 MM BTU/HR)										
SRU Thermal Oxidizer (EU00169)	25	54	6	0.25	7	49	6	0.25	6	Stack Test (10/29/93) - Avg 3 runs
NHT Stripper Reboiler (EU00144)	24	133	15	0.1	7	133	15	0.1	7	AP-42 - 100 lbs/MM scf
KHT Charge Heater (EU00151)	14	53	6	0.1	3	55	6	0.1	3	AP-42 - 100 lbs/MM scf
Melvandale Asphalt Heater (EU00316)	14	36	4	0.1	2	39	4	0.1	2	AP-42 - 100 lbs/MM scf
Unifiner H2 Compressor #1(7C1)	15 - (440 BHP)	7,132 hrs operation	4	8.4 lb/hr	30	7,872 hrs operation	4	8.4 lb/hr	33	Emission factor from 05/22/99 test
Unifiner H2 Compressor #2 (7C2)	15 - (440 BHP)	8,333 hrs operation	4	8.4 lb/hr	35	7,800 hrs operation	4	8.4 lb/hr	33	Emission factor from 05/22/99 test
Unifiner H2 Compressor #3 (7C3)	15 - (440 BHP)	8095 hrs operation	4	8.4 lb/hr	34	7,896 hrs operation	4	8.4 lb/hr	33	Emission factor from 05/22/99 test
FCC Wet Gas Compressor (12C5)	22 - (660 BHP)	4104 hrs operation	5	8.4 lb/hr	17	5,400 hrs operation	5	8.4 lb/hr	23	Emission factor from 05/22/99 test
FCC Wet Gas Compressor (12C6)	15 - (440 BHP)	3696 hrs opeation	3	8.4 lb/hr	15	2,232 hrs operation	3	8.4 lb/hr	9	Emission factor from 05/22/99 test
Therminol Heater (North) (EU00164)	7.5	19	2	0.1	1.0	6	1	0.1	0.3	AP-42 - 100 lbs/MM scf
Therminol Heater (South) - (EU00165)	7.5	31	4	0.1	2	45	5	0.1	2	AP-42 - 100 lbs/MM scf
Subtotal (Non-Sigma Sources)	174	488	57		151	489	58		151	

PROCESS HEATERS AND BOILERS - GARYVILLE, LA REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr -gas	MM BTU/hr (hhv)	lb/MM Btu	(tpy)	MMscf/yr -gas	MM BTU/hr (hhv)	lb/MM Btu	(tpy)	
PROCESS HEATERS/BOILERS (>100 MM BTU/HR)										
Platformer Interheaters [12-1401]	449	3,648	427	0.063	118	2,970	356	0.063	98	Stack Test - 0.063 lb/MM BTU (hhv) - 08/21/02 (Avg 3 runs)
Boiler #1 (Unit 42) [42-1401]	385	1,721	202	0.058	51	1,673	201	0.058	51	Stack Test (02/20/02) - 0.058 lb/MM BTU (hhv) Avg 3 runs - heater has FGR/LNBs
Crude Atmospheric Heater [10-1401]	315	2,700	316	0.4	554	2,324	279	0.4	488	Stack Test (04/23/96) - 0.4 lb/MM BTU (Avg)
Crude Atmospheric Heater [10-1402]	315	2,760	323	0.4	566	2,466	296	0.4	518	Stack Test (04/23/96) - 0.4 lb/MM BTU (Avg)
Hf Alky Isostripper Reboiler [27-1401 & 1402]	295	1,916	224	0.268	263	1,813	217	0.268	255	Stack Test (01/95) - 0.268 lb/MM BTU (Avg)
ROSE Deasphalting [7-1401]	243	1,245	146	0.05	32	1,268	152	0.05	33	Stack Test of 0.05 lb/MM BTU (hhv) - 02/01/02
Platformer Interheater #5 [12-1403]	231	1,698	199	0.1	87	1,612	193	0.1	85	Stack test of Platformer Heater - 05/20/03
FCC Charge Heater [25-1401]	187	1,382	162	0.125	89	1,426	171	0.125	94	Stack Test (08/13/02) - 0.125 lb/MM BTU (hhv)
Crude Vacuum Heater [10-1403]	152	1,216	142	0.09	56	1,074	129	0.09	51	Stack Test 08/16/02 - Avg 3 runs (hhv) Low NOx Burners - Vacuum off-gas
Crude Vacuum Heater [10-1404]	152	1,169	137	0.094	56	1,053	126	0.094	52	Stack Test 08/16/02 - Avg 3 runs (hhv) Low NOx Burners - Vacuum off-gas
Old Boiler #1 [36-1601]	132	881	104	0.098	44	1,051	126	0.098	54	Stack Test 12/18/02 - Avg 3 runs (hhv)
Old Boiler #2 [36-1602]	132	857	101	0.076	34	1,064	128	0.076	42	Stack Test 12/18/02 - Avg 3 runs (hhv)
Subtotal (>100 MM BTU/hr)	2,987	21,193	2,482	0.179	1,950	19,794	2,373	0.175	1,821	
PROCESS HEATERS/BOILERS (>40 MM BTU/HR & < 100 MM BTU/HR)										
HGO Charge Heater [15-1401]	99	505	59	0.104	27	643	77	0.104	35	Average of two stack tests on 04/02/02 & 11/04/02 - (hhv)
HGO Reboiler Heater [15-1403]	86	503	59	0.1	26	515	62	0.1	27	AP-42 Emission Factor - 100 lbs/MM scf
Sat's Gas Hot Heater [22-1401]	80	514	60	0.092	24	502	60	0.092	24	Stack Test 03/06/01 (hhv) - avg 3 runs
Distillate Hydrotreater Charge Heater [14-1401]	76	572	67	0.103	30	478	57	0.103	26	Stack Test 02/01/01 (hhv) - avg 3 runs
Distillate Hydrotreater StripperReboiler [14-1402]	68	516	60	0.08	21	533	64	0.08	22	Stack Test 02/01/01 (hhv) - avg 3 runs
Naphtha Hydrotreater Reboiler [11-1402]	67	514	60	0.11	29	496	59	0.11	29	Stack Test 11/06/02 (hhv) - avg 3 runs
Platformer Debutanizer Reboiler [12-1402]	67	598	70	0.11	33	496	59	0.11	28	Stack Test 11/06/02 (hhv) - avg 3 runs
Naphtha Hydrotreater Heater [11-1401]	58	454	53	0.1	23	340	41	0.1	18	Stack Test 12/19/02 (hhv) - avg 3 runs
Subtotal (>40 MM BTU/hr & <100 MM BTU/hr)	602	4,176	489	0.100	214	4,003	480	0.100	210	
HEATER/BOILER TOTALS (SIGMA EQ.)	**3,588**	**25,369**	**2,970**	**0.166**	**2,163**	**23,797**	**2,852**	**0.163**	**2,030**	
PROCESS HEATERS/BOILERS (< 40 MM BTU/HR)										
LSR Hydrotreater Charge Heater (100-85)	19	118	12.5	0.12	7	97	12	0.12	6	Average of stack test results of Sat's Gas Heater and Naphtha Reboiler
LSR Hydrotreater Reboiler (101-85)	17	91	9.7	0.12	5	91	11	0.12	6	Average of stack test results of Sat's Gas Heater and Naphtha Reboiler
Thermal Drying Unit Heater	4	9	1	0.12	1	39	5	0.12	2	Average of stack test results of Sat's Gas Heater and Naphtha Reboiler
Subtotal (<40 MM BTU/hr)	40	218	23.2	0.120	12	227	27	0.120	14	

PROCESS HEATERS BOILERS AT ROBINSON, IL REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr -gas bbls/yr - oil	MM BTU/hr (hhv)	lb/MM scf - gas lb/1000 gallons - oil	(tpy)	MMscf/yr -gas bbls/yr - oil	MM BTU/hr (hhv)	lb/MM scf - gas lb/1000 gallons - oil	(tpy)	
PROCESS HEATERS/BOILERS (>100 MM BTU/HR)										
Platformer Heater [16-F-3A,3B,3C,3D]	625	3,598	483	0.047	99	2,833	339	0.047	70	Stack Test -(8/13/03) - 66 lb/MM scf (avg)
Crude Atmospheric Heater [1-F-1]	531	3,701	486	130	241	3,652	453	130	237	Stack Test -(6/24/97) - 131 lbs/MM scf (avg)
Boiler No. 3 [59-F-3]										
Fuel Gas	248	644	83	0.10	40	1,069	139	0.10	61	Stack Test - (06/26/97) - Avg 3 runs
Fuel Oil		11,047	8			12	0			
Boiler No. 4 [59-F-4]										
Fuel Gas	248	975	126	0.10	57	1,104	143	0.10	63	Stack Test - (06/26/97) - Avg 3 runs
Fuel Oil		6,483	5			920	1			
Boiler No. 5 [59-F-5]										
Fuel Gas	248	498	64	336	84	664	86	336	112	Stack Test - (06/26/97) - 336 lb/MM scf
Fuel Oil		1	0	47	0	29	0	47	0	AP-42 - 47lbs/1000 gallons
Boiler No. 6 [59-F-6]										
Fuel Gas	248	383	49	0.10	22	670	87	0.10	38	Stack Test - (06/26/97) - Avg 3 runs
Fuel Oil		3	0			694	0			
Ultraformer Reactor Preheater [3-F-1]	260	1,984	235	230	228	1,814	184	230	209	Stack test in January 2001
Ultraformer Reactor Preheater [3-F-2]	170	1,084	128	230	125	1,089	111	230	125	Stack test in January 2001
HF Alky Isostripper Reboiler [7-F-1]	154	1,058	139	280	148	757	102	280	106	AP-42 - 280 lbs/MM scf
Crude Vacuum Heater [1-F-2]										
Fuel Gas	143	608	80	130	40	564	70	130	37	Stack Test -(6/24/97) - 131 lbs/MM scf
Fuel Oil		1,973	1	47	2	5,777	4	47	6	AP-42 - 47lbs/1000 gallons
Regular Coker Heater [90-F-1]	134	280	33	0.14	20	543	64	0.14	39	Stack Test (12/17/02) - Avg 3 runs
Ultraformer Reactor Preheater [3-F-3]	131	622	74	0.22	71	587	60	0.22	58	Stack test (08/06/2003) - Avg 3 runs
FCC Feed Preheater [82 - F -2]	110	280	36	0.07	11	458	59	0.07	18	Stack Test (12/17/02) - Avg 3 runs
Ultraformer Reactor Preheater [3-F-4]	110	391	46	0.22	45	463	47	0.22	45	Stack test (08/06/2003) - Avg 3 runs
Special Coker Heater [87-F-103]	108	680	80	0.03	10	598	70	0.03	9	Stack Test (08/12/2003) - Avg 3 runs
Subtotal (> 100 MM BTU/hr)										
Fuel Gas	3,466	16,786	2,141	148	1,240	16,865	2,013	145	1,227	
Fuel Oil		19,507	14	47	2	7,432	5	47	6	
PROCESS HEATERS/BOILERS (>40 MM BTU/HR & < 100 MM BTU/HR)										
Unicracker Splitter Reboiler [4-F-3]	55	380	50	100	19	348	46	100	17	AP-42 - 100 lbs/MM scf
Unicracker Debutanizer Reboiler [4-F-4]	52	407	54	100	20	349	46	100	17	AP-42 - 100 lbs/MM scf
Ultrafiner Stripper Heater [2-F-2]	80	481	57	100	24	326	33	100	16	AP-42 - 100 lbs/MM scf
Distillate Hydrotreater Stripper [69-F-2]	88	617	80	47	14	540	70	47	13	Stack Test - (12/21/93) - 47 lb/MM scf (avg)
Distillate Hydrotreater Charge [69-F-1A]	59	192	25	55	5	230	30	55	6	Stack Test - (12/21/93) - 55 lb/MM scf (avg)
Distillate Hydrotreater Charge [69-F-1B]	59	160	21	55	4	188	24	55	5	Stack Test - (12/21/93) - 55 lb/MM scf (avg)

PROCESS HEATERS BOILERS AT ROBINSON, IL REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr -gas bbls/yr - oil	MM BTU/hr (hhv)	lb/MM scf - gas lb/1000 gallons - oil	(tpy)	MMscf/yr -gas bbls/yr - oil	MM BTU/hr (hhv)	lb/MM scf - gas lb/1000 gallons - oil	(tpy)	
Sat's Gas #1 Debutanizer Reboiler [8-F-1]	57	224	29	100	11	203	27	100	10	AP-42 - 100 lbs/MM scf
Regular Coker Preheater [90-F-2]	55	100	12	100	5	215	25	100	11	AP-42 - 100 lbs/MM scf
Platformer Debutanizer Reboiler [16-F-4]	51	249	33	100	12	203	24	100	10	AP-42 - 100 lbs/MM scf
Ultraformer Regeneration Heater [3-F-7]	50	107	8	100	5	119	8	100	6	AP-42 - 100 lbs/MM scf
Sat's Gas #1 Debutanizer Reb. [23-F-1]	45	214	28	100	11	182	24	100	9	AP-42 - 100 lbs/MM scf
Naphtha Hydrotreater Heater [16-F-1]	44	183	25	100	9	151	18	100	8	AP-42 - 100 lbs/MM scf
Subtotal (>40 MM BTU/hr & <100 MM BTU/hr)	695	3314	421	-----	141	3054	377	84	129	
TOTALS (Applied towards Sigma Equation)										
Fuel Gas	4161	20,100	2,562	137	1,382	19,919	2,390	136	1,356	
Fuel Oil		19,507	14	4.76	2	7,432	5	36.53	6	
Overall	4161		2,576		1,384		2,395		1,361	
PROCESS HEATERS & BOILERS (< 40 MM BTU/HR)										
Penex Heater (77F-1 & 2)	29	208	25	100	10	209	27	100	10	AP-42 - 100 lbs/MM scf
Ultrafiner Reactor Heater [2-F-1]	39	304	36	100	15	210	21	100	11	AP-42 - 100 lbs/MM scf
Hydrotreater Reactor Heater [4-F-1]	39	178	24	100	9	99	13	100	5	AP-42 - 100 lbs/MM scf
Hydrotreater Reactor Heater [4-F-2]	39	167	22	100	8	172	23	100	9	AP-42 - 100 lbs/MM scf
Naphtha Hydrotreater Reboiler (16F-2)	37.5	175	19	100	9	163	19	100	8	AP-42 - 100 lbs/MM scf
FCC Peabody Heater (82-F-1) - startup	60.5	30	4	100	2	40	5	100	2	AP-42 - 100 lbs/MM scf
Subtotal (< 40 MM BT/hr)	243	1062	130	100	53	893	109	100	45	

PROCESS HEATERS BOILERS AT ST. PAUL PARK, MN REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr - gas Bbls/yr - Oil	MM BTU/hr (hhv)	lb/MM BTU - gas lb/1000 gallons -oil	(tpy)	MMscf/yr - gas Bbls/yr - Oil	MM BTU/hr (hhv)	lb/MM SCF or BTU - gas lb/1000 gallons -oil	(tpy)	
PROCESS HEATERS/BOILERS (> 100 MM BTU/HR)										
#2 Crude Charge (2-B-3)										
Fuel Gas	178	977	113	0.09	48.7	964	117	0.09	49.9	Stack Test (05/00) - 0.090 lb/MM BTU (avg)
Fuel Oil		15,432	11			14,569	10			
HDH Charge (32-B-1)										
Fuel Gas	116	242	28	280	34	296	36	280	41	AP-42 - 280 lbs/MM scf fuel
Fuel Oil		42,557	29	47	42	42,476	29	47	42	AP-42 - 47 lbs/1000 gallons
#1 Crude Fractionator Chg (1-B-7)										
Fuel Gas	112	394	66	0.29	84	460	77	0.29	98	Stack Test on 12/11/02 (Fuel Gas and Oil)
Fuel Oil		28,346				30,651				
#2 Vac Charge (5-B-1)										
Fuel Gas	105	188	22	0.038	5	251	31	0.038	5	Stack test on 01/08/03 - 0.038 lb/MM BTU
Fuel Oil		13,472	9			2,150	1			
Subtotal										
Fuel Gas	510	1,801	229	0.17	172	1,971	260	0.17	194	
Fuel Oil		99,807	49	0.19	42	89,846	41	0.23	42	
PROCESS HEATERS/BOILERS (>40 MM BTU/HR & < 100 MMBTU/HR)										
H2 Reformers (38-B-1 &2)	90	478	27	0.001	0	430	26	0.001	0	Stack Test (05/00) - 0.001 lb/MM BTU (avg)
Hot Oil Heater (34-B-2)										
Fuel Gas	99	220	26	100	11	264	32	100	13	AP-42 - 100 lbs/MM scf fuel
Fuel Oil		24,111	17	47	24	27,036	19	47	27	AP-42 - 47 lbs/1000 gallons
Reformer Chg/Interheaters (36-B-2, 3,4)	83	173	20	0.12	11	183	22	0.12	12	Stack Test (06/26/03)
NU/chg/Stab Rblr/Strip Rblr (2-B-1, 2, 3)	72	325	38	0.08	13	315	38	0.08	13	Stack Test (05/00) - 0.08 lb/MM BTU (avg)
Plat Rx Charge (3-B-4)	70	404	47	0.102	21	385	47	0.102	21	Stack Test (05/00) - 0.102 lb/MM BTU (avg)
#1 Crude Pre-flash Heater (1-B-6)	65	292	34	100	15	352	43	100	18	AP-42 - 100 lbs/MM scf fuel
Dehex Reboiler (10-B-1)										
Fuel Gas	64	145	17	100	7	156	19	100	8	AP-42 - 100 lbs/MM scf fuel
Fuel Oil		22,182	15	47	22	21,126	15	47	21	AP-42 - 47 lbs/1000 gallons
Guard Case Rx Charge (36-B-1)	63	126	15	0.134	9	129	16	0.134	9	Stack Test (05/00) - 0.134 lb/MM BTU (avg)
#4 Boiler (16-B-4)										
Fuel Gas	58	132	15	100	7	126	15	100	6	AP-42 - 100 lbs/MM scf fuel
Fuel Oil		4,918	3	47	5	3,979	3	47	4	AP-42 - 47 lbs/1000 gallons
#6 Boiler (16-B-6)										
Fuel Gas	58	127	15	100	6	129	16	100	6	AP-42 - 100 lbs/MM scf fuel
Fuel Oil		5,382	4	47	5	5,630	4	47	6	AP-42 - 47 lbs/1000 gallons

PROCESS HEATERS BOILERS AT ST. PAUL PARK, MN REFINERY

Emission Source	Design Firing Rate	OPERATING YEAR 1999				OPERATING YEAR 2000				BASIS FOR EMISSION FACTOR
		Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	Fuel Consumption	Firing Rate	Emission Factor	NOx Emissions	
	MM BTU/hr (hhv)	MMscf/yr - gas Bbls/yr - Oil	MM BTU/hr (hhv)	lb/MM BTU - gas lb/1000 gallons -oil	(tpy)	MMscf/yr - gas Bbls/yr - Oil	MM BTU/hr (hhv)	lb/MM SCF or BTU - gas lb/1000 gallons -oil	(tpy)	
PROCESS HEATERS/BOILERS (>40 MM BTU/HR & < 100 MMBTU/HR) - Cont'd										
Vacuum Heater (1-B-5)	53	150	18	100	8	157	19	100	8	AP-42 - 100 lbs/MM scf fuel
Plat No. 1 Interheater (3-B-7)	50	401	47	0.114	23	126	15	0.114	8	Stack Test (04/10/02)
FCC Charge (8-B-1)	50	98	11	100	5	364	44	100	18	AP-42 - 100 lbs/MM scf fuel
Isostripper Reboiler (28-B-1)										
Fuel Gas	50	155	18	100	8	100	12	100	5	AP-42 - 100 lbs/MM scf fuel
Fuel Oil		*9,000*	*6*	47	9	11,563	8	47	11	AP-42 - 47 lbs/1000 gallons
DU Chg/Depent Reboiler (29-B-1 & 2)	47	130	15	100	7	181	22	100	9	AP-42 - 100 lbs/MM scf fuel
Subtotal										
Fuel Gas	971	3356	364	0.094	150	3,397	388	0.091	155	
Fuel Oil		65,593	45	0.33	65	69,334	48	0.33	68	
HEATER/BOILER TOTALS (Applied Towards Sigma Equation)										
Fuel Gas	1482	5,157	594	0.124	321	5,368	648	0.123	349	
Fuel Oil		165,400	95	0.26	107	159,180	89	0.28	110	
Total	1481.8		688		428		737		459	
HEATERS/BOILERS (<40 MM BTU/HR)										
Plat No. 2 Interheater (3-B-8)	39	154	17	0.11	8	144	16	0.11	8	Stack Test (06/00) - Avg 3 runs
#5 Boiler (16-B-5)	39	53	6	0.1	3	144	16	0.1	7	AP-42 - 100 lbs/MM scf fuel
No. 2 Interheater (36-B-6W)	39	85	10	0.13	5	95	10	0.13	6	Stack Test (06/00) - Avg 3 runs
DDS Charge (37-B-1)	39	298	33	0.047	7	84	9	0.047	2	Stack Test (06/00) - Avg 3 runs
Stripper Reboiler (37-B-2)	29	172	19	0.059	5	216	23	0.059	6	Stack Test (06/00) - Avg 3 runs
No. 3 Interheater (36-B-6E)	23	33	4	0.115	2	165	18	0.115	9	Stack Test (06/00) - Avg 3 runs
Desulf Charge (34-B-1)	33	117	13	0.1	6	35	4	0.1	2	AP-42 - 100 lbs/MM scf fuel
Subtotal	239.7	912	102	0.080	36	883	96	0.093	39	

PROCESS HEATERS AND BOILERS AT TEXAS CITY, TX REFINERY

Emission Source	Design Firing Rate MM BTU/hr (hhv)	OPERATING YEAR 1999 Fuel Consumption MMscf/yr	OPERATING YEAR 1999 Firing Rate MM BTU/hr (hhv)	OPERATING YEAR 1999 Emission Factor lb/MM BTU	OPERATING YEAR 1999 NOx Emissions (tpy)	OPERATING YEAR 2000 Fuel Consumption MMscf/yr	OPERATING YEAR 2000 Firing Rate MM BTU/hr (hhv)	OPERATING YEAR 2000 Emission Factor lb/MM BTU	OPERATING YEAR 2000 NOx Emissions (tpy)	BASIS FOR EMISSION FACTOR
PROCESS HEATERS/BOILERS (> 100 MM BTU/HR)										
Alky Heater (H-8)	197	1216	138	0.068	41	1079	117	0.068	35	0.068 lb.MM BTU - 06/00
#5 Topper Htr. (H-92)	182	1402	159	0.176	123	1259	137	0.176	105	0.176 lb/MM BTU - 12/99
Subtotal (>100 MM BTU/hr)	379	2618	297	0.13	164	2338	254	0.13	140	
PROCESS HEATERS/BOILERS (> 40 MM BTU/HR & < 100 MM BTU/HR)										
Boiler #1 (B-2A)	95	557	63	0.14	39	496	54	0.14	33	0.185 lb/MM BTU - 11/99 0.10 lb/MM BTU - 09/00 Avg Factor of 0.14 lb/MM BTU
Boiler #2 (B-2B)	95	270	31	0.12	16	432	47	0.12	25	Nox CEM Data
Boiler #3 (B-2C)	95	391	44	0.12	23	252	27	0.12	14	(03/01/03 - 10/25/03)
Boiler #4 (B-2D)	95	461	52	0.14	32	404	44	0.14	27	0,185 lb/MM BTU - 11/99 0,10 lb/MM BTU - 09/00 Avg Factor of 0,14 lb/MM BTU
Udex Stripper Htr (H-1)	63	438	50	0.067	15	459	50	0.067	15	0.067 lb/MM BTU - 1994 0.049 lb/MM BTU - 12/94
Born Heater (H-9)	62	355	42	0.04	7	368	43	0.04	8	0.04 lb/MM BTU - 11/00
Platformer Interm. Htr. (H-2)	58	310	35	0.077	12	279	30	0.077	10	0.077 lb/MM BTU - 11/00
#4 Topper Htr (H-6)	50	299	35	0.056	9	398	47	0.056	11	0.056 lb/ MM BTU - 11/99
Platformer Htr. (H-3)	50	441	50	0.099	22	397	43	0.099	19	0.099 lb./ MM BTU - 1/94
Subtotal (>40 & <100 MM BTU/hr)	663	3522	403	0.10	174	3485	385	0.10	161	
GAS FIRED RECIPROCATING COMPRESSORS										
FCC GasCon - M7 (E-5)	35	24	3	5.88	77	29	3.5	5.88	90	Stack Test (04/2000) - Avg
FCC GasCon - M8 (E-4)	35	54	6	4.42	116	47	5.6	4.42	108	Stack Test (04/2000) - Avg
FCC GasCon - M9 (E-3)	18	54	7	3.38	103	47	5.6	3.38	83	Stack Test (04/2000) - Avg
FCC GasCon - M13 (E-6)	37	56	7	2.48	76	47	5.6	2.48	61	Stack Test (04/2000) - Avg
M15 Compres-Plat (E-2) - gas fired	25	32	4	4.76	83	52	6	4.76	129	Stack Test (01/1994) - Avg
M15 Compres-Plat (E-1) - gas fired	25	33	4	3.51	61	55	7	3.51	101	Stack Test (01/1994) - Avg
Subtotal	151	253	31		518	224	27		471	
HEATER/BOILER TOTALS (Applied towards the Sigma Equation)										
Totals (> 40 MM BTU/hr)	1193	6393	731		856	6046	665		773	
PROCESS HEATERS/BOILERS (< 40 MM BTU/HR)										
FCCU Superheater (B-1)	35	270	31	0.10	14	270	31	0.10	14	AP-42 - 100 lbs/MM scf fuel
TDU Salt Heater (P-70)	4	27	3	0.10	1	0.0	0.0	0.10	0.0	AP-42 - 100 lbs/MM scf fuel
FCCU Air Preheat (H-94)	55	0	0	0.10	0.0	4	0.4	0.10	0.2	AP-42 - 100 lbs/MM scf fuel
Subtotal	94	297	34		15	274	32		14	

APPENDIX D

TO FIRST REVISED CONSENT DECREE

Design and Operating Criteria For NOx Reducing Systems

FIRST REVISED CONSENT DECREE

APPENDIX D

PARAGRAPH 12 DESIGN AND OPERATING CRITERIA FOR NOx REDUCING SYSTEMS

All air pollution control equipment designed pursuant to this appendix will be designed and built in accordance with accepted engineering practice and regulatory requirements that may apply.

I. Lo TOx System

A. Design Considerations

1. Quench Vessel and Capacity

a. Dimensions
   i. Internal or External to wet gas scrubber
b. Quench Water Capacity
c. Initial and Final Temperatures
d. Quench Water Composition
e. WGS Parameters (if applicable)
   i. Number of quench nozzles in service
   ii. Quench rate
   iii. Quench water composition
   iv. Make up water rate
   v. Temperature and Pressure
   vi. Pressure drop

2. Reaction Temperature Profile

a. Location and Number of Sensors

3. Reaction Residence Time

a. Reaction Vessel Temperature and Pressure
b. Gas Flow Rates and Residence Time

4. Oxygen Supply

a. Type of Supply and Purity
b. Capacity of Oxygen Supply

5. Ozone Generators and Injection

    a. Number and Capacity
    b. Electricity Demand
    c. Concentration Ozone and Volume Oxygen/Ozone Produced and Injected
    d. Flow Distribution Manifold
    e. Injection Grid / Nozzles
        i. Number
        ii. Size
        iii. Location
        iv. Controls
    g. Ozone Slip
    h. Cooling water supply rates for ozone generators

6. Flue Gas Characteristics

    a. Inlet/Outlet NO_x Concentration
    b. Flue Gas Volumetric Flow
    c. Inlet/Outlet Temperature Range
    d. Inlet/Outlet SO_2/SO_3 Concentrations
    e. Inlet/Outlet $CO/H_2O/O_2$ Concentrations
    f. Inlet/Outlet Particulate/Ash Loading and Characteristics

7. Efficiency

    a. Designed to Outlet NO_x Concentration
    b. Designed to Efficiency

8. Safety Considerations

9. Compliance with Applicable Laws and Regulations

B. Operating Considerations

1. Reaction Temperature Profile

2. Reaction Residence Time

    a. Residence Time at Temperature and Pressure
    b. Gas Flow Rates

3. Ozone Addition

    a. Ozone Addition Rates
    b. Ozone Slip

4. Flue Gas Characteristics

    a. Outlet NO_x Concentration
    b. Flue Gas Volumetric Flow
    c. Inlet/Outlet Temperature Range
    d. Outlet SO_2 Concentrations
    e. Outlet CO/O_2 Concentrations

5. WGS Operating Parameters

    a. Number of quench nozzles in service
    b. Quench rate
    c. Quench water composition
    d. Make up water rate
    e. Temperature and Pressure
    f. Pressure drop

6. Efficiency

    a. Actual Outlet NO_x Concentration

7. Compliance with Applicable Laws and Regulations

II. Enhanced Selective Non-Catalytic Reduction

A. Design Considerations

1. Reductant Addition

    a. Type (Anhydrous Ammonia, or Aqueous Ammonia)
    b. Primary and Enhanced Reductant Addition Rates
    c. Composition of Enhanced Reductant
    d. Diluent Type and Rate
    e. Flow Distribution Manifold

f. Injection Grid / Nozzles
   i. Number
   ii. Size
   iii. Location
   iv. Controls
g. Ammonia Slip

2. Flue Gas Characteristics

   a. Outlet NO_x Concentration
   b. Flue Gas Volumetric Flow
   c. Inlet/Outlet Temperature Range
   d. Inlet/Outlet SO_2/SO_3 Concentrations
   e. Inlet/Outlet $CO/H_2O/O_2$ Concentrations

3. Efficiency

   a. Designed to Outlet NO_x Concentration

4. Safety Considerations

5. Startup and Shutdown Considerations

6. Compliance with Applicable Laws and Regulations

B. Operating Considerations

1. Reductant Addition

   a. Reductant Addition Rates
   b. Ammonia Slip
   c. Enhanced Reductant Composition

2. Flue Gas Characteristics

   a. Outlet NO_x Concentration
   b. Flue Gas Volumetric Flow
   c. Inlet/Outlet Temperature Range
   d. Outlet SO_2 Concentrations
   e. Outlet COO_2 Concentrations

3. Efficiency

    a. Actual Outlet NO_x Concentration

4. Safety Considerations

5. Startup and Shutdown Considerations

6. Compliance with Applicable Laws and Regulations

APPENDIX E

TO FIRST REVISED CONSENT DECREE

Parametric Emissions Monitoring Systems for Heaters and Boilers with Capacities Between 150 and 100 mmBTU/hr (HHV)

FIRST REVISED CONSENT DECREE

APPENDIX E

PARAMETRIC EMISSIONS MONITORING SYSTEMS FOR HEATERS AND BOILERS WITH CAPACITIES BETWEEN 150 AND 100 mmBTU/HR

MAP shall continuously monitor NOx and CO emissions from-heaters and boilers with capacities of less than 150 mmBTU/hr (HHV) but greater than 100 mmBTU/hr (HHV) in accordance with this Appendix to demonstrate compliance with the NOx requirements established for Controlled Heaters and Boilers pursuant to Paragraph 13., to establish the Baseline for any PAL for NOx and CO, and to demonstrate compliance with the CAP. MAP shall continuously monitor by either (1) installing and operating a NOx or CO CEMS or (2) installing a Parametric Emission Monitoring System (PEMS) for NOx or CO. A CEMS directly measures the gas concentration of NOx or CO in a stack. A PEMS is a mathematical model that predicts the gas concentration of NOx or CO in the stack based on a set of operating data. Consistent with the CEMS data frequency requirements of 40 CFR Part 60, the PEMS shall calculate a pound per million BTU value at least once every 15 minutes, and all of the data produced in a calendar hour shall be averaged to produce a calendar hourly average value in pounds per million BTU. The 24 calendar hour averages in a given calendar day shall be averaged and used as the calendar daily average concentration in Appendix P.

The types of information needed for a PEMS are described below. The list of instruments and data sources shown below represent an ideal case. However at a minimum, each PEMS shall include continuous monitoring for at least items 3-5 below. MAP will identify and use existing instruments and refinery data sources to provide sufficient data for the development and implementation of the PEMs parametric software.

Basis Instrumentation:

1. Absolute Humidity reading (one instrument per refinery, if available)
2. Fuel Density, Composition and/or specific gravity - On line readings (it may be possible if the fuel gas does not vary widely, that a grab sample and analysis may be substituted)
3. Fuel flow rate
4. Firebox temperature
5. Stack excess oxygen reading
6. Airflow to the firebox (if known or possibly estimated)
7. Process variable data - steam flow rate, temperature and pressure - process stream flow rate, temperature & pressure, etc.

Computers & Software:

1. Windows NT computer or Honeywell Node - Windows NT is preferred so "PC Anywhere" software can be used to monitor the PEMs setup.
2. "Software CEM" to calculate the "predicted" NOx or CO emissions
3. Data management software to write the compliance monitoring reports

Calibration and Setup:

1. Data will be collected for a period of 3 to 7 days of all the data that is to be used to construct the mathematical model. The data will be collected over an operating range that represents 80% to 100% of typical heater/boiler operation

2. Collect data for "End of Run" and "Start of Run", if appropriate

3. A"Sensor Validation" analysis shall be conducted to make sure the system is collecting data properly

4. Stack Testing (by subcontractor) to develop the actual emissions data for comparison to the collected parameter data

5. Development of the mathematical models and installation of the model into the computer.

MAP may install these PEMS in the State of Minnesota. If Minnesota has enacted requirements that are directly applicable to these PEMS then the performance specifications shall be referenced as part of their installation and operation.

The heaters/boilers that are being considered for installation of PEMS are at the St. Paul Park Refinery and are as follows:

HDH Charge Heater (No. 5-32-B-1) with a capacity 116 mmBTU/hr (HHV))

Alkylation & FCCU Heater (5-8 and 28-B-1) with a capacity 100 mmBTU/hr (HHV))

The monitoring protocol for the PEMS to be installed on the heaters shall be based on EPA's "Alternative Monitoring Protocol" for an Industrial Furnace.

The elements of a protocol for a PEMS shall include:

1. Applicability

a. Identify source name, location, and emission unit number(s)

b. Identify the type of industry;

c. Identify the process of interest;

d. Identify the regulations that apply (e.g.; NSPS, NESHAP, SIP, and/or Consent Decree);

e. Identify the pollutant(s) subject to monitoring (information on major/area source determination).

f. Provide expected dates of monitor compliance demonstration testing

2. Source Description

a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g.; sampling ports in the stack);

b. Provide a discussion of process or equipment operations that are known to significantly affect emissions or monitoring procedures (e.g., batch operations, plant schedules, product changes).

3. Control Equipment Description

a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g.; sampling ports in the stack);

b. List monitored operating parameters and normal operating ranges;

c. Provide a discussion of operating procedures that are known to significantly affect emissions (e.g., catalytic bed replacement schedules, ESP rapping cycles, fabric filter cleaning cycles).

4. Monitoring System Design

a. Install, calibrate, operate, and maintain a continuous PEMS;

b. Provide a general description of the software and hardware components of the PEMS including manufacturer, type of computer, name(s) of software product(s), monitoring technique (e.g., method of emission correlation). Manufacturer literature and other similar information shall also be submitted, as appropriate;

c. List all elements used in the PEMS to be measured (e.g., pollutant(s), other exhaust constituent(s) such as O_2 for correction purposes, process parameter(s), and/or emission control device parameter(s));

d. List all measurement or sampling locations (e.g., vent or stack location, process parameter measurement location, fuel sampling location, work stations);

e. Provide a simplified block flow diagram of the monitoring system overlaying process or control device diagram (could be included in Source Description and Control Equipment Description);

f. Provide a description of sensors and analytical devices (e.g., thermocouple for temperature, pressure diaphragm for flow rate);

g. Provide a description of the data acquisition and handling system operation including sample calculations (e.g., parameters to be recorded, frequency of measurement, data averaging time, reporting units, recording process);

h. Provide checklists, data sheets, and report format as necessary for compliance determination (e.g., forms for record keeping).

5. Support Testing and Data for Protocol Design

a. Provide a description of field and/or laboratory testing conducted in developing the correlation (e.g., measurement interference check, parameter/emission correlation test plan, instrument range calibrations):

b. Provide graphs showing the correlation, and supporting data (e.g., correlation test results, predicted versus measured plots, sensitivity plots, computer modeling development data).

6. Initial Verification Test Procedures

a. Perform an initial relative accuracy test (RA test) to verify the performance of the PEMS over the permitted operating range. The PEMS must meet the relative accuracy requirement of the applicable Performance Specification in 40 CFR Part 60, Appendix B. The test shall utilize the test methods of 40 CFR Part 60, Appendix A.

b. Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation, and typical of the anticipated range of operation, test the selected parameter for three RA test data sets at the low range, three at the normal operating range and three at the high operating range of that parameter, for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration:

c. Maintain a log or sampling report for each required stack test listing the emission rate in accordance with the applicable emission limitations:

d. Demonstrate the ability of the PEMS to detect excessive sensor failure modes that would adversely affect PEMS emission determination. These failure modes include gross sensor failure or sensor drift.

e The owner or operator shall demonstrate the ability to detect sensor failures that would cause the PEMS emissions determination to drift significantly from the original PEMS value.

f. The owner or operator may use calculated sensor values based upon the mathematical relationships established with the other sensors used in the PEMS. The owner or operator shall establish and demonstrate the number and combination of calculated sensor values which would cause PEMS emission determination to drift significantly from the original PEMS value.

7. Quality Assurance Plan

a. Provide a list of the input parameters to the PEMS (e.g., transducers, sensors, gas chromatograph, periodic laboratory analysis), and a description of the sensor validation procedure (e.g., manual or automatic check):

b. Provide a description of routine control checks to be performed during operating periods (e.g., preventive maintenance schedule, daily manual or automatic sensor drift determinations, periodic instrument calibrations)

c. Provide minimum data availability requirements and procedures for supplying missing data (including specifications for equipment outages for QA/QC checks):

d. List corrective action triggers [e.g., response time deterioration limit on pressure sensor, use of statistical process control (SPC) determinations of problems, sensor validation alarms]:

e. List trouble-shooting procedures and potential corrective actions:

f. Provide an inventory of replacement and repair supplies for the sensors:

g. Specify, for each input parameter to the PEMS, the drift criteria for excessive error (e.g.: the drift limit of each input sensor that would cause the PEMS to exceed relative accuracy requirements):

h. Conduct a quarterly electronic data accuracy assessment tests of the PEMS.

i. Conduct semiannual RA tests of the PEMS. Annual RA tests may be conducted if the most recent RA test result is less than or equal to 7.5%. Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation and typical of the anticipated range of operation, test the selected parameter for three RA test data pairs at the low range, three at the normal operating range, and three at the high operating range of that parameter for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration.

8. PEMS Tuning

a. Perform tuning of the PEMS provided that the fundamental mathematical relationships in the PEMS model are not changed.

b. Perform tuning of the PEMS in case of sensor recalibration or sensor replacement provided that the fundamental mathematical relationships in the PEMS model are not changed.

APPENDIX F

TO FIRST REVISED CONSENT DECREE

NOx and CO Source Testing and Portable Analyzer Requirements for Heaters and Boilers < 100 mmBTU/hr (HHV)

FIRST REVISED CONSENT DECREE

APPENDIX F

NOX AND CO SOURCE TESTING AND PORTABLE ANALYZER
<u>REQUIREMENTS FOR HEATERS AND BOILERS < 100 mmBTU/HR</u>

For heaters and boilers < 100 mmBTU/hr and > 40 mmBTU/hr that are controlled for NOx pursuant to Paragraph 13., and for all heaters and boilers < 100 mmBTU/hr that are included in any NOx or CO PAL, MAP shall use this appendix to monitor and demonstrate compliance.

I. <u>NOx Monitoring for Controlled Heaters and Boilers < 100 mmBTU/hr</u>

MAP shall either follow one of Methods 7-7E for NOx, or use a portable analyzer and follow the requirements of Conditional Test Method - 022 ("CTM-022"), in conjunction with 40 CFR Part 60 Appendix A, Method 19 to determine pounds per million BTU, to conduct 3 one-hour test runs to demonstrate compliance with the NOx emission limits in pounds per million BTU established pursuant to Paragraph 13. The test shall be conducted within 90 days of establishing the emission limit in the permit as required by Paragraph 13.

II. <u>NOx and CO Monitoring for Establishing the Baseline and Demonstrating Compliance with the Cap for PALs for Heaters and Boilers < 100 mmBTU/hr</u>

MAP shall follow one of Methods 7-7E for NOx and one of Methods 10-10B for CO, in conjunction with 40 CFR Part 60 Appendix A, Method 19 to determine pounds per million BTU, to establish the baseline and demonstrate compliance with the NOx and CO Caps established pursuant to Paragraph 26. The initial tests shall be conducted prior to submitting the application for the PAL pursuant to Paragraph 26. Thereafter, by March 31 of each calendar year, MAP shall conduct the annual test to establish the revised actual concentration to ensure continued compliance with the Cap and by June 30 of each calendar year, MAP shall begin to use the revised actual concentration as the calendar daily average concentration in Appendix P.

III. NOx and CO Monitoring for Establishing the Baseline and Demonstrating Compliance with the Cap for PALs for Heaters and Boilers < 40 mmBTU/hr

MAP shall either follow one of Methods 7-7E for NOx and one of Methods 10-10B for CO, or use a portable analyzer and follow the requirements of Conditional Test Method - 022 ("CTM-022") for NOx and use the same procedures in CTM-022 for CO, in conjunction with 40 CFR Part 60 Appendix A, Method 19 to determine pounds per million BTU, to conduct 3 one-hour test runs to establish the baseline and demonstrate compliance with the NOx and CO Caps established pursuant to Paragraph 26. The initial tests shall be conducted prior to submitting the application for the PAL pursuant to Paragraph 26. Thereafter, by March 31 of each calendar year, MAP shall conduct the annual test to ensure continued compliance with the Cap and by June 30 of each calendar year, MAP shall begin to use the revised actual concentration as the calendar daily average concentration in Appendix P.

APPENDIX G

TO FIRST REVISED CONSENT DECREE

Fuel Oil Phase-out

FIRST REVISED CONSENT DECREE

APPENDIX G

FUEL OIL PHASE-OUT

Heater/Boiler Des.	Baseline Amount (bbls/yr)	Allowable Amount (bbls/yr)	Date of Reduction
CANTON			
Number 11 Boiler (4-16-B-11)	67,146	0	04/30/2003
HDS Charge Heater (4-32-B-1)	8,852	0	04/30/2003
Number 1 Boiler (4-16-B-1)	1,887	0	04/30/2003
Number 2 Boiler (4-16-B-2)	2,968	0	04/30/2003
Subtotal	80,853	0	
CATLETTSBURG			
# 5 Crude Charge Heater (1-41-B-1)	56,961	0	01/31/2004
#2 Crude Charge Heater (1-2-B-3)	43,189	0	01/31/2004
#2 Vacuum Charge Heater (1-2-B-1)	435	0	01/31/2004
# 3 Crude Charge Heater (2-23-B-3)	6	0	01/31/2004
# 3 Crude Charge Heater (2-23-B-4)	5,597	0	01/31/2004
Subtotal	106,188	0	

Heater/Boiler Des.	Baseline Amount (bbls/yr)	Allowable Amount (bbls/yr)	Date of Reduction
DETROIT[1/]			
CO Boiler (27-BR-6)	120,761	0	8/30/2003
Alkylation Reboiler (9-H-2)	0	60,335 bbls/yr	8/30/2003
Subtotal	120,761	60,335 bbls/yr	
ROBINSON			
Boilers #3, #4, #5, & #6 [59-F-3, 4, 5, & 6]	9,708	0	12/31/2001
Crude Vacuum Heater (1-F-2)	3,875	0	12/31/2001
Subtotal	13,583	0	

1/ MAP shall limit the sulfur content of oil fired at Detroit to 1.0 weight percent sulfur.

Heater/Boiler Des.	Baseline Amount (bbls/yr)	Allowable Amount (ton/yr)	Date of Reduction
ST. PAUL PARK[2]			
# 2 Crude Charge Heater (2-B-3)	15,000	See ftn. 2	04/01/2004
HDH Charge Heater (32-B-1)	42,516	See ftn. 2	04/01/2004
#1 Crude Fractionator (1-B-7)	29,500	See ftn. 2	04/01/2004
#2 Crude Vacuum Heater (5-B-1)	7,811	See ftn. 2	04/01/2004

[2] The St. Paul Park Refinery has accepted and will continue to maintain an annual sulfur dioxide emission cap of 281 tons per year from burning fuel oil in its process heaters and boilers so as to meet the requirements of Paragraph 15.A of this First Amended Consent Decree. This emission cap represents a 58% reduction from the baseline values in Appendix G to the August 2001 Decree. It is based upon burning 67,673 barrels of fuel oil with a sulfur content of 1.4 weight percent. By no later than 90 days after the Lodging of this First Amended Consent Decree, MAP shall submit an application to the MPCA to incorporate this emissions cap in a federally-enforceable permit. MAP shall burn fuel oil only in the St. Paul Park Refinery heaters and boilers which were equipped to do so prior to the Lodging of the August 2001 Consent Decree. MAP shall submit in the semi-annual report due in 2006, the tons per year of sulfur dioxide emissions from each heater and boiler since January 1, 2005, and shall make an annual submission in the first semi-annual report of each calendar year. MAP shall calculate the tons emitted by the following equation:

$$\sum_{i=1}^{n} [DRFO_i \times FOD_i \times (SC_i/100) \times 2/2000] \leq \text{the limit in tons of SO2 per year}$$

Where:

$DRFO_i$ = amount of fuel oil combusted at the refinery for day i in gal/day

FOD_i = average density of fuel oil combusted at the refinery for day i in lb/gal

SC_i = average sulfur content of the oil combusted at the refinery for day i in wt % sulfur

n = prior 365 calendar days

In demonstrating compliance with this Paragraph, MAP shall measure and retain records of the following for each day on which fuel oil is combusted: amount of fuel oil combusted (weight and volume), density, and sulfur content.

Heater/Boiler Des.	Baseline Amount (bbls/yr)	Allowable Amount (ton/yr)	Date of Reduction
Dehexanizer Reboiler (10-B-1)	21,654	See ftn. 2	04/01/2004
#4 Boiler (16-B-4)	4,450	See ftn. 2	04/01/2004
# 6 Boiler (16-B-6)	5,500	See ftn. 2	04/01/2004
Hot Oil Heater (34-B-2)	25,574	See ftn. 2	04/01/2004
Iso-Stripper Reboiler/ FCCU Charge Heater (28-B-1)/(8-B-1)	10,281	See ftn. 2	04/01/2004
Subtotal	162,286	281 tpy	
TOTALS	**483,671**	**60,335 bbls/yr from Detroit** **281 tons/yr from St. Paul Park**	

APPENDIX H

TO FIRST REVISED CONSENT DECREE

NSPS Subpart J Compliance Schedule for Heaters and Boilers

FIRST REVISED CONSENT DECREE

APPENDIX H

NSPS SUBPART J COMPLIANCE SCHEDULE FOR HEATERS AND BOILERS

Source	Date of Compliance	Method of Compliance
Canton		
CCR Charge Heaters [4-33-B-1 thru 4]	09/01/01	Submit AMP (Lock Hopper Gas from CCR)
Vacuum Heater	11/01/01	Submit AMP (Caustic Treater System Off-Gas)
Catlettsburg		
HRU Boilers	09/01/01	Submit AMP (Caustic Oxidizer off-gas)
HPCCR Charge Heaters [2-102-B-1A, 1B, 1C]	09/01/01	Submit AMP (Lock Hopper Gas from CCR)
LPCCR Charge Heaters [I-44-B-1&2]	09/01/01	Submit AMP (Lock Hopper Gas from CCR)
Saturates Gas Heater [2-30-B-1]	09/01/01	Submit AMP (Disulfide Gas from Merox Unit)
Detroit		
FCC Charge Heater [11-H-1]	09/01/01	Submit AMP (Disulfide Gas from Merox Unit)
Heater(s) fed by Ref. Fuel Gas Header	02/04/02	Submit AMP (De-Ethanizer Off-Gas – Alky Unit)
Heater(s) fed by Ref. Fuel Gas Header	02/04/02	Submit AMP (Propylene De-Ethanizer Off-Gas Stream to Ref Fuel Gas)
CCR Inter-Heaters	12/31/05	Submit AMP (CCR Lock Hopper Vent Gas)

Source	Date of Compliance	Method of Compliance
CCR Charge Heater	12/31/05	Submit AMP (CCR Chlorosorb (regenerator) Vent Gas)
Garyville		
FCC Charge Heater [84-78]	09/07/00	Submitted AMP/Disulfide Gas from LPG Merox
Saturates Gas Heater [92-80]	09/07/00	Submitted AMP/Disulfide Gas from C3/C3 Merox
SRS Hot Oil Heater [124-91]	09/07/00	Submitted AMP/ Condenser Off-gas
Platformer Chg Heater	09/07/00	Submitted AMP/Lock Happer Gas from CCR
Coker Heater	10/01/01	Submitted AMP for disulfide off-gas
Robinson[1/]		
Ultrafiner Heaters [2-F-1 & 2]	12/31/05	Install H2S CEMS on hydrogen drum or reroute vent gas streams
Crude Heater [1-F-1]	12/31/03	CEM on stack/ Amine treated Vacuum off-Gas
Platformer Heaters [16F-3A, B, C]	09/01/01	Submit AMP/ Lock Hopper Gas from CCR
Alkylation Reboiler [7F-1]	09/01/01	Submit AMP/ Disulfide Gas from LPG Merox

[1/] (Robinson currently injects three process streams downstream of its central fuel gas knock out drum. The refinery will either submit an AMP or reroute these three streams by 12/31/2002.).

Source	Date of Compliance	Method of Compliance
All Other Heaters and Boilers	12/31/02	Reroute/Monitor off-gas from high pressure separator (2c-3), vessel 3-k-10, and vessel 3-c-10
St. Paul Park		
Hydrogen Heaters	6/30/03	Reroute hydrogen off-gas stream from Hydrogen Heaters back to the Hydrogen Plant natural gas process feed system
DDS Charge Htrs	6/30/03	Reroute purged fuel gas from DDS Charge Heaters to the sour fuel gas drum
Texas City		
FCC Steam Generator [B-1]	6/30/03	Shut down
UDEX Stripper Heater [H-1]	6/30/03	Shut down
Boilers 1& 4 [27-B-1 & 4]	6/30/03	Shut down
Boilers 2 & 3 [27-B-2 & 3]	7/31/07	Build new amine treating, sour water treating, SRP and tail gas treating facilities[2]
Alkylation Heater Udex Borne Heater	7/31/07	Build new amine treating, sour water treating, SRP and tail gas treating facilities

[2] MAP's Texas City Refinery currently sends spent (sour) amine to amine regeneration facilities at the Valero Refinery in Texas City. Valero processes the acid gas that is generated in its Sulfur Plants. On occasion, Valero does not accept MAP's spent amine which results in MAP's combustion of refinery fuel gas in excess of the 160 ppm H2S limit of 40 C.F.R. Part 60, Subpart J. The Texas City Refinery will install and operate a new amine treating, sour water treating, SRP and tail gas treating facilities by no later than July 31, 2007.

Source	Date of Compliance	Method of Compliance
[02H6]	7/31/07	Build new amine treating, sour water treating, SRP and tail gas treating facilities
Platformer Interheaters [09H2]	7/31/07	Build new amine treating, sour water treating, SRP and tail gas treating facilities
Platformer Charge Heater [09H1]	7/31/07	Build new amine treating, sour water treating, SRP and tail gas treating facilities
#5 Topper Charge Crude Heater [H-6]	2/28/06[3]	Burn natural gas or build new amine treating, sour water treating, SRP and tail gas treating facilities
Topper #4 Charge Crude Heater [H-92]	2/28/06[3]	Burn natural gas or build new amine treating, sour water treating, SRP and tail gas treating facilities

[3] MAP complied with NSPS Subparts A and J for the period between the Date of Lodging of the August 2001 Consent Decree and March 1, 2005, for the ## 4 and 5 Topper Crude Charge Heaters.

APPENDIX I

TO FIRST REVISED CONSENT DECREE

Schedule for Complying with the FCCU New Source Performance Standards (NSPS)

Appendix I

SCHEDULE FOR COMPLYING WITH THE FCCU NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Refinery	Sulfur Dioxide		Particulate Matter		Carbon Monoxide	
	NSPS Limit (see below)	CEM Installation	NSPS Limit (1 lb/1000 lb coke burn)	CEM Installation (Opacity or equivalent)	NSPS Limit (500 ppm CO)	CEM Installation
Canton	9.8 lb/1000 lb coke 05/30/2004 (Note 1a)	12/31/2001	1.0 lb/1000 lb 04/30/2004 (Note 4)	Date of Lodging	500 ppmv 12/31/2001	12/31/2001
Catlettsburg						
RCC	50 pppmv or 9.8 lb/1000 lb coke - 7 day 6/30/2004 (Note 1b & 2)	Date of Lodging	1 lb/1000 lb 6/30/2004 (Note 2)	Date of Lodging	500 ppmv Date of Lodging	Date of Lodging
FCC	Shutdown 6/30/2004 (Note 1b & 2)	Date of Lodging	Shutdown 6/30/2004 (Note 2)	Date of Lodging	Shutdown 6/30/2004 (Note 2)	Date of Lodging
Detroit	9.8 lb/ 1000 lb coke 05/30/2004 (Note 1a)	12/31/2001	1 lb/1000 lb 04/30/2005 (Note 4)	Date of Lodging	6/30/2003 (Note 5)	6/30/2002
Garyville	50 ppmv - 7day 12/31/2001	12/31/2001	1 lb/1000 lb Date of Lodging	Approved AMP	500 ppmv Date of Lodging	Date of Lodging
Robinson	50 ppmv - 7day Date of Lodging	Date of Lodging	1 lb/1000 lb Date of Lodging	Approved AMP	500 ppmv Date of Lodging	Date of Lodging
St. Paul Park	9.8 lb/1000 lb 12/30/2004 (Note 1a)	5/31/2002	1.0 lb/1000 lb 12/31/2007 (Note 4)	Date of Lodging	4/30/2005	5/30/2002
Texas City	50 ppmv - 7 day 6/30/2003 (note 3)	2/28/2003	1 lb/1000 lb 8/30/2003 (note 3)	Submit AMP (06/30/2003)	500 ppmv 6/30/2003 (note 3)	11/30/2002

Notes

(1a) These three refineries may comply with the NSPS limit of 9.8 lbs SO2 per 1000 lbs of coke burn rate. The compliance dates reflect the date at which the refinery much obtain an enforceable permit limit after peforming the 6 month test period, the 12-month Optimization Study, and 6 months to submit study, finalize short term and long term limit, and obtain permit limit

(1b) Refinery has agreed to take NSPS limit of 50 ppm - 7day average. During Hydrotreater outages, Catlettsburg may comply with NSPS limit of 9.8 lb/1000 lb coke burn

(2) Catlettsburg will complete the reconfiguration of the two FCCUs by June 30, 2004 at which point both will meet the NSPS limit; the FCCU may be shutdown in meeting this limit.

(3) Texas City may need up to 6 months to correct any operating problems with the wet gas scrubber and certify comliance with the NSPS limit

(4) Date corresponds to the installation of the third stage separator (TSS)

(5) Detroit plans to shutdown existing CO Boiler and build new dedicated FCCU Stack by 06/30/2003.

APPENDIX J

TO FIRST REVISED CONSENT DECREE

NSPS Subpart J Compliance Schedule for Flares

FIRST REVISED CONSENT DECREE

APPENDIX J

NSPS SUBPART J COMPLIANCE SCHEDULE FOR FLARES

Source	Date of Compliance	Method of Compliance
CANTON		
North Flare	12/31/2001	Submit AMP, Reroute FW vent
South Flare	12/31/2001	Submit AMP
CATLETTSBURG		
Lube/Petrochem Flare (1-14-FS-2)	12/31/2008	Low Pressure Vent Recovery System, AMP, Scrubber
South Area Flare (2-11-FS-1)	12/31/2008	Low Pressure Vent Recovery System, AMP, reroute FW vapors
HF Alkylation Flare (2-11-FS-3)	12/31/2008	Low Pressure Vent Recovery System, AMP
New North Area Flare	12/31/2008	Low Pressure Veny Recovery System, Reroute foul water vents, AMP
Air Assisted Flare (2-11-FS-5)		Was shut down on 11/19/99
Pitch Flare (1-14-FS-3)	12/31/2008	Low Pressure Vent Recovery System, Reroute streams, AMP
RCCS Flare (2-11-FS-4)	06/01/2004	Reroute streams, submit AMP
Vapor Destruction Unit [1-7-B-1]	09/01/2001	Submit AMP

DETROIT

Unifiner Flare	12/31/2005	Reroute naphtha skimmer; vent and submit AMPs for other streams
Alkylation Flare	12/31/2005	Reroute Alky CDR vent stream
Crude Flare	01/30/2005	Submit AMP for Crude Spent Caustic Drum Vent
CP Cracking Plant Flare	01/30/2005	Submit AMPs for several streams

GARYVILLE

South Flare [69-73]	12/31/2001	Reroute Unit 19 SW surge drum
North Flare [83-78]	12/31/2001	Reroute Unit 33 SW surge drum
Marine Vapor Recovery [107-90]	09/07/2000	Submitted AMP

ROBINSON

Flare System [#1 - #6]	12/31/2008	Reroute several stream[1]
Wastewater Flare [2-F-1 & 2]	12/31/2008	Reroute several streams

[1] In 2002, MAP installed a temporary flare gas recovery system for coker blowdown streams to minimize SO2 emissions until a permanent flare gas recovery system was in place. By no later than December 31, 2006, MAP shall install a coker blowdown flare gas recovery system on the Robinson #3 and #4 Flare System. By no later than December 31, 2008, MAP shall install a second permanent flare gas recovery system, separate and apart from the coker blowdown flare gas recovery system, to recover miscellaneous vent gas streams.

ST. PAUL PARK

Main Flare	06/30/2004	Reroute several streams, install recovery compressors, submit AMP
Loading Rack Flare (Temporary when condenser out)	03/30/2002	Submit AMP

TEXAS CITY

Marine Vapor Combustor	07/19/2000 06/30/04	Submit AMP Resubmit AMP
Alklation Flare	07/19/2000 06/30/04	Submit AMP Resubmit AMP
Wastewater Treatment Flare	07/19/2000 12/31/05	Submit AMP Resubmit AMP
Main Flare	12/31/2007	Reroute streams, install recovery compressor, submit AMP

APPENDIX K

TO FIRST REVISED CONSENT DECREE

Study of Breakthrough in Dual Carbon Canisters

APPENDIX K

STUDY OF BREAKTHROUGH IN DUAL CARBON CANISTERS

1. MAP shall conduct a study of dual carbon canisters designed to determine the concentration of VOCs or benzene that may be emitted from the primary (lead) carbon canister in a dual series before VOCs above background or benzene above 1 ppm is emitted from the secondary (tail) carbon canister.

2. MAP shall select a total of ten dual carbon canisters from its Catlettsburg, Garyville, and Texas City Refineries. In making the selection, MAP shall review the frequency with which each primary carbon canister historically has been changed out, and shall include in the study, to the extent possible, dual canister systems in which the life expectancy of the primary canisters vary. MAP shall include, if possible, at least five dual carbon canisters where the life expectancy of the primary canister is approximately one month or less. MAP may include two 150 gallon-size carbon canisters and eight 55 gallon-size carbon canisters.

3. By no later than thirty (30) days after the Date of Lodging of the Consent Decree, MAP shall submit to EPA a proposal that identifies the location and size of each of the selected dual carbon canisters and the historical life expectancy of the primary canister in each series. If EPA comments upon MAP's proposal, the parties shall endeavor to come to agreement informally. Unless, within thirty (30) days after receipt of MAP's proposal, EPA provides comments, MAP shall commence the study ("Commencement of the Study"), and shall notify EPA of the date of the Commencement of the Study.

4. By no later than seven days after the Commencement of the Study, MAP shall monitor each of the selected dual carbon canister systems for breakthrough between the primary and

secondary carbon canisters and for emissions from the secondary canister. Thereafter, MAP shall monitor for breakthrough between the primary and secondary canisters in accordance with the frequency specified in 40 C.F.R. § 61.354(d).

5. On the first monitoring occasion in which breakthrough between the primary and secondary canister reaches 50 ppm or greater of VOCs, MAP shall monitor, on that same day, emissions from the secondary canister. On a daily basis thereafter, MAP shall monitor emissions from both the primary and secondary canister.

6. At such time as emissions from the secondary canister reach either a VOC concentration above background or a benzene concentration of 1 ppm, MAP shall replace the primary canister with the secondary canister. The provisions of this Appendix K, and not Subparagraph 18.E.iii, shall apply to the timing of the replacement of any primary canister that is a subject of this study, for so long as the carbon canister is monitored for purposes of the study. After the carbon canister no longer is monitored for purposes of this Study, the provisions of Subparagraph 18.E.iii. shall govern the timing of the replacement of the primary canisters, unless and until EPA redefines the meaning of "breakthrough" pursuant to Subparagraph 18.E.i.

7. Contemporaneously with each monitoring event undertaken pursuant to this Appendix K, MAP shall maintain a written record of the time, date, and monitoring results.

8. For each dual carbon canister in which the primary canister has a life expectancy of one month or less, MAP shall conduct the monitoring specified in Paragraph 5 for one year. For each dual carbon canister in which the primary canister has a life expectancy of greater than one month, MAP shall conduct the monitoring specified in Paragraph 5 for the greater of: (i) one year; or (ii) three cycles of the subject carbon canister system, not to exceed two years.

9. For each dual carbon canister in which the primary canister has a life expectancy of one month or less, by no later than one year and three months after the date of the Commencement of the Study, MAP shall submit a report to EPA that includes, but is not limited to, the monitoring data, the replacement dates of the primary carbon canisters, and MAP's recommendations regarding the concentration of VOCs or benzene that may be emitted from the primary canister in a dual series before VOCs above background or benzene above 1 ppm is emitted from the secondary canister. By no later than sixty (60) days after receipt of the report, EPA and MAP jointly shall evaluate the breakthrough limits set forth in Subparagraph 18.E.i, to determine if any revisions to that Subparagraph are necessary with respect to carbon canisters in which the primary canister has a life expectancy of one month or less.

10. For each dual carbon canister in which the primary canister has a life expectancy of greater than one month, MAP shall submit a report that contains the same information set forth in Paragraph 9 by no later than ninety (90) days after completing all required monitoring. By no later than sixty (60) days after receipt of the report, EPA and MAP jointly shall evaluate the breakthrough limits set forth in Subparagraph 18.E.i, to determine if any revisions to that Subparagraph are necessary with respect to carbon canisters in which the primary canister has a life expectancy of greater than one month.

APPENDIX L

TO FIRST REVISED CONSENT DECREE

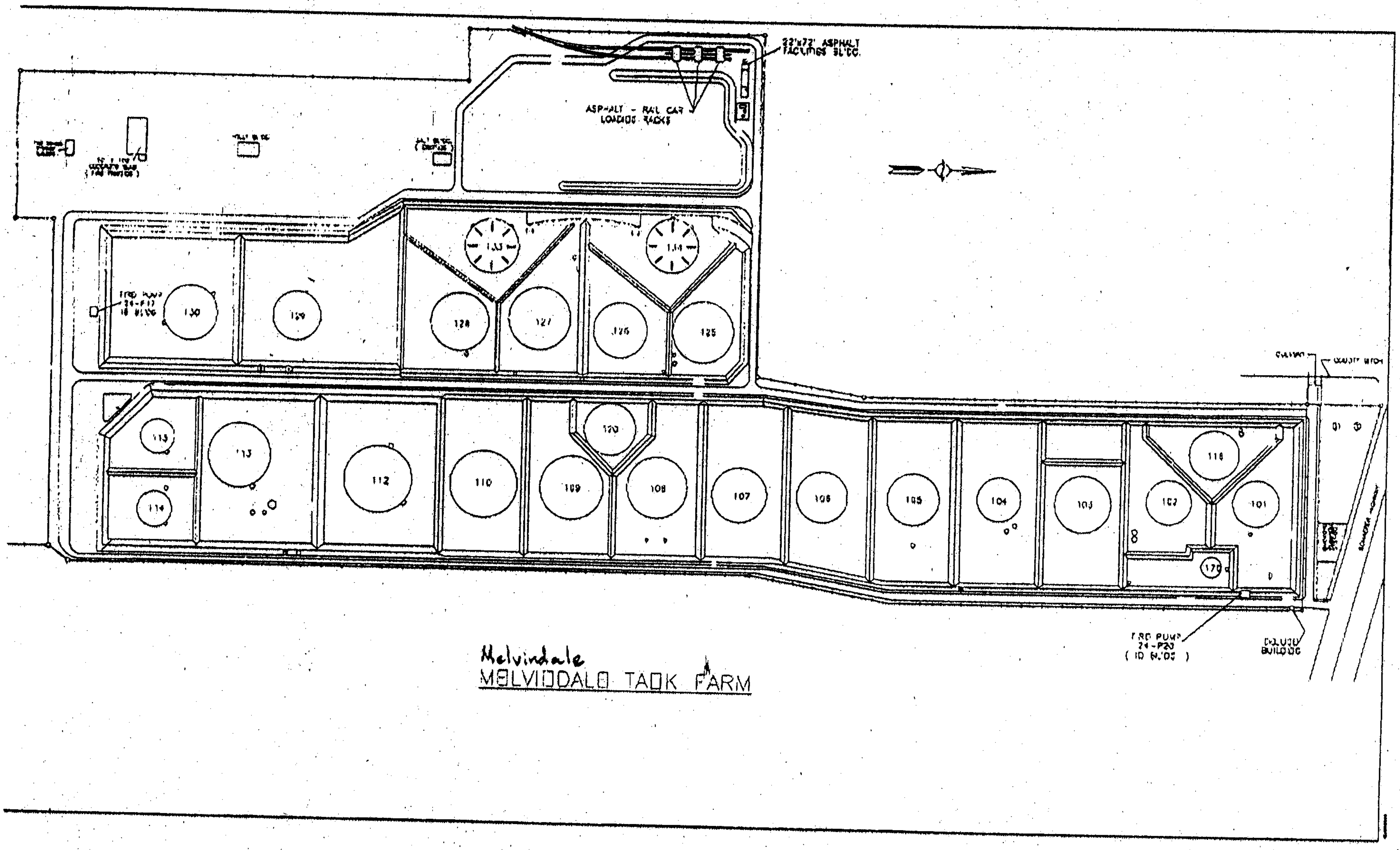
[OMITTED]

APPENDIX M

TO FIRST REVISED CONSENT DECREE

Diagram of the Melvindale and Crude Tank Farms at the Detroit Refinery

FIRST REVISED CONSENT DECREE
APPENDIX M



Melvindale
MELVINDALE TANK FARM

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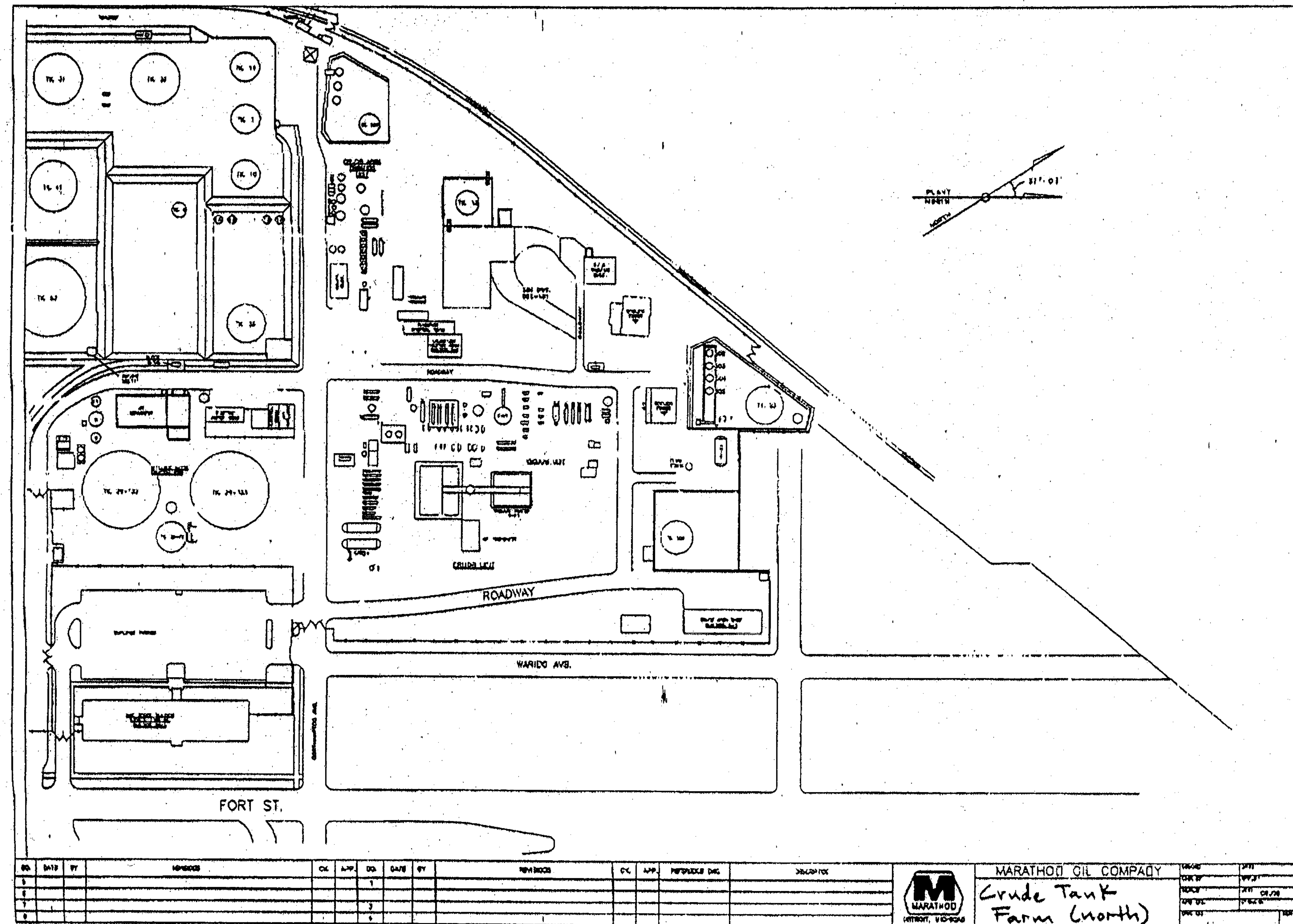

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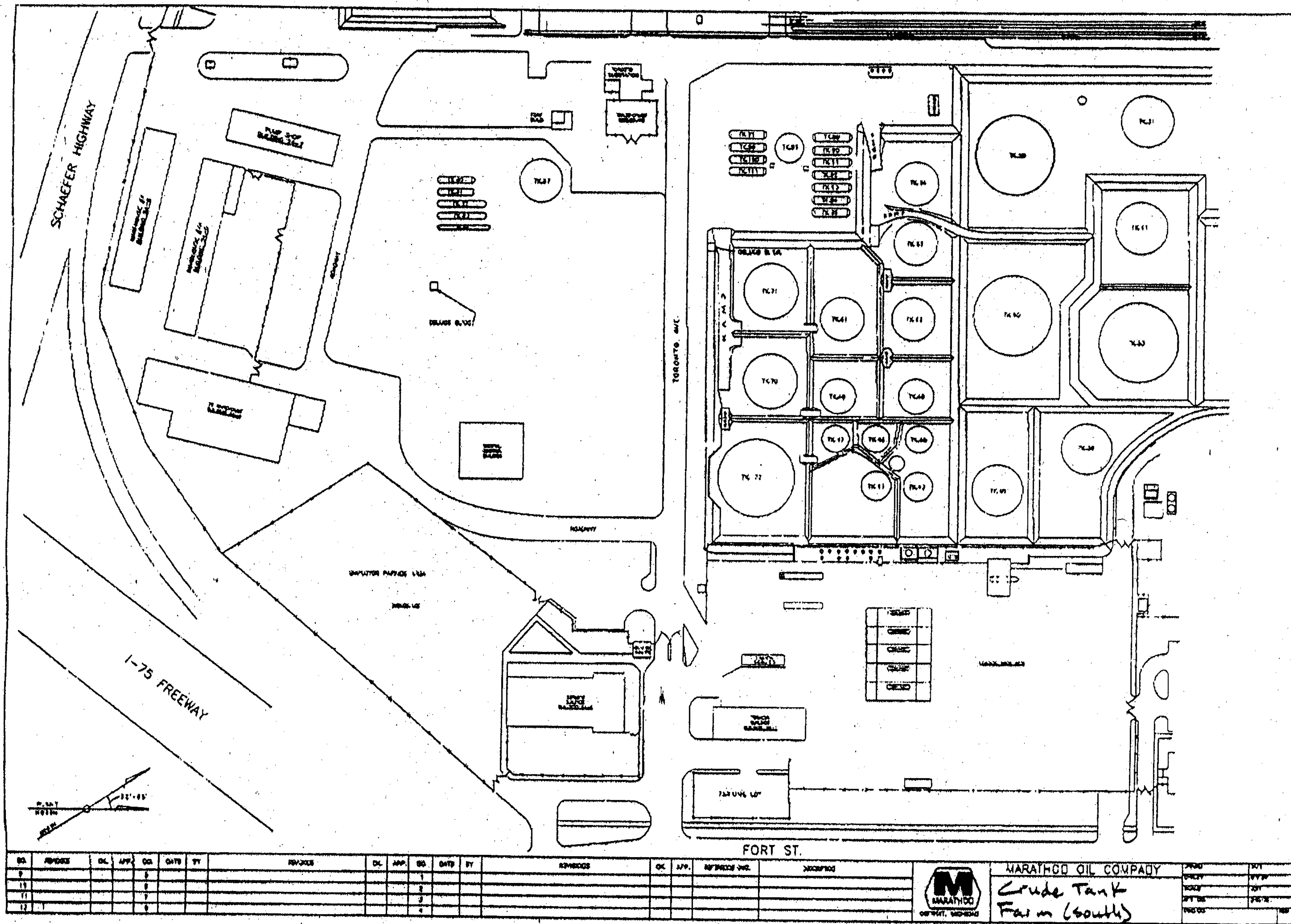

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APPENDIX N

TO FIRST REVISED CONSENT DECREE

[OMITTED]

APPENDIX O

TO FIRST REVISED CONSENT DECREE

Logic Diagram for Paragraph 22

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APPENDIX O
(LOGIC DIAGRAM FOR PARAGRAPH 22)

ALL FLARING INCIDENTS

Was the Root Cause:
- error resulting from careless operation by the personnel charged with the responsibility for the SRPs, TGUs, or Upstream Process Units? or
- equipment failure due to a failure by MAP to operate and maintain that equipment in a manner consistent with good engineering practices? or

Yes → Paragraph 48 applies except in cases of Force Majeure

No ↓

Did the Flaring incident:
- result in emissions of SO_2 at a rate greater than 20 lbs/hr continuously for three consecutive hours and no scheduled maintenance exception? or
- cause the total number of Flaring Incidents in a rolling 12 month period to exceed 5?

Yes → Paragraph 48 applies with caveats set forth in Paragraph 22.C.i.b

No ↓

Is this the first time for the Root Cause of this Flaring Incident?

No →

Is the Root Cause on the list of agreed upon Malfunctions?

Yes → STOP

No → Paragraph 48.d applies with caveats set forth in Paragraph 22.C.i.c.2

Yes ↓

Was the Root Cause sudden, infrequent, and not reasonably preventable through the exercise of good engineering practice?

No → Implement Corrective Action pursuant to Paragraph 22.B

Yes ↓

Establish and update a list of agreed-upon Malfunctions → STOP

APPENDIX P

TO FIRST REVISED CONSENT DECREE

Baseline, Cap and Compliance Determination for the PAL(s)

FIRST REVISED CONSENT DECREE

APPENDIX P

BASELINE AND CAP DETERMINATION FOR THE PAL(S)

I. Determining the Baseline – MAP shall establish baseline emissions for emission units within any PAL established pursuant to Paragraph 26 using this Appendix separately for each pollutant. MAP shall include the following emissions units within each PAL: all FCCUs, all SRUs (excluding flares, thermal oxidizers), all heaters (>5 mmBTU/hr), and all boilers (>5 mmBTU/hr). The foregoing sentence shall not apply to incinerators except those associated with SRUs. MAP may propose, for EPA approval, to include additional emissions units within a PAL. EPA will consider MAP's proposal based on availability, accuracy and reliability of baseline data, adequacy of monitoring, relative contribution to the Cap, and any other relevant and available information. In addition, MAP may propose for EPA approval alternate methods to calculate baseline emissions and emission rates used to determine compliance with the PAL.

A. Determining Baseline Concentrations for NOx, SO_2, CO and PM for Calendar years 2000-2002. The baseline concentration shall be in lb/mmBTU separately for each fuel fired for heaters and boilers for all pollutants, in ppmvd @ 0% O2 for all other emissions units for NOx, SO_2, and CO, in lb/1000 lb coke for PM emissions from FCCUs, in lb/dscf for PM emissions from all other units, and shall be determined as follows:

1. For calendar years 2000-2002, for emissions units that have CEMS installed the baseline concentration shall be established using the average concentration in that time period, or if CEMS were not installed in that time period, at least 3-months of CEMS data from another representative time period, with adjustment for variability of operating parameters during this period as compared to the operating parameters for calendars years 2000-2002, and excluding periods of operation that result in emissions above allowable levels.

2. For calendar year 2002, for emissions units that have CEMS installed by December 31, 2001, the baseline concentration shall be established using the average concentration from January 1, 2002 through December 31, 2002, and excluding periods of operation that result in emissions above allowable levels.

3. For emissions units that do not have CEMS installed the baseline concentration shall be established as follows:

   a. For heaters and boilers > 40 mmBTU/hr conduct a series of source tests and parametric analysis as provided in Appendix E or provide 30 consecutive days of CEMS data (from temporary CEMS);

b. For heaters and boilers < 40 mmBTU/hr either conduct a series of source tests and parametric analysis as provided in Appendix E, or conduct tests measuring concentration using a portable analyzer as provided in Appendix F; and

c. For all other emissions units, submit a proposal for EPA approval for the concentration with supporting information as part of the PAL application required by Paragraph 26.

B. Determining Baseline Utilization for Calendar Years 2000-2002. The baseline utilization for each calendar year for each emissions unit shall be the average utilization of that emissions unit as follows:

1. For FCCUs utilization shall be in terms of an annual average pounds of coke burn per hour with an annual average weight percent hydrogen on coke and annual average CO Boiler auxiliary fuel firing rate in mmBTU/hr for each fuel at annual average combustion O2 by volume percent, combustion temperature in degrees Fahrenheit, and air pre-heat temperature in degrees Fahrenheit;

2. For sulfur recovery units shall be in terms of long tons of sulfur produced per day, at an annual average acid gas feed rate in scfd, NH3 gas feed rate in scfd, air feed rate to reactor furnace (RF) in scfd, annual average acid and NH3 gas concentration in percent by volume, and annual average natural gas feed rate in mol/hr;

3. For heaters and boilers utilization shall be in terms of annual average fuel firing rate for each fuel fired in mmBTU/hr for each fuel at annual average combustion O2 by volume percent, combustion temperature in degrees Fahrenheit, and air pre-heat temperature in degrees Fahrenheit.

C. Determining Baseline Emissions. MAP shall determine baseline emissions for an emissions unit to be included in the PAL as follows:

1. For FCCUs, baseline emissions in tons per year for a particular calendar year shall be calculated as follows:

$$BE_{FCCU} = BC_{FCCU} \text{ x } [BRF_{FCCU} + BCOBF_{FCCU}] \text{ x } 379 \text{ x } MW \text{ x } [8760/2000]$$

$$BRF_{FCCU} = [(3.64 \text{ x wt \% } H_B) + (1.53 \text{ x } \{100\text{-wt \% } H_B\})]$$

$\times$ [BCBR]

$BCOBF_{FCCU}$ = $[(BUO_{COB}) \times (9190) + (BUFG_{COB}) \times (BF_{d\text{-}fg}) + BUNG_{COB}) \times (8710)]$

where:

BC_{FCCU} = baseline concentration in ppmvd @ 0 % O2 for that calendar year

MW = molecular weight of the pollutant in pounds per pound-mole

wt % H_B = annual average weight percent hydrogen on coke for that calendar year as determined by either continuous measurement or daily measurements of CO2 and moisture in the FCCU flue gas.

BCBR = annual average FCCU regenerator coke burn rate in pounds of coke per hour for that calendar year as determined continuously or on a daily basis by heat balance and flue gas constituents.

BUO_{COB} = baseline utilization rate of CO boiler on oil in mmBTU/hr for that calendar year

$BUFG_{COB}$ = baseline utilization rate of CO boiler on fuel gas in mmBTU/hr for that calendar year

$BUNG_{COB}$ = baseline utilization rate of CO boiler on natural gas in mmBTU/hr for that calendar year

$BF_{d\text{-}fg}$ = the baseline flow factor on a dry basis for fuel gas and shall be calculated for that calendar year for each application using the equation in section 3.2. of Method 19 in 40 CFR Part 60 Appendix A.

2. For SRUs, baseline emissions in tons per year for a particular calendar year shall be calculated as follows:

BE_{SRU} = $BC_{SRU} \times [BFRI] \times MW \times [8760/2000]$

BFRI	=	BWG + [(BNG + BTA)/1-B%EA] - BSP

Where:

BFRI	=	baseline incinerator flue gas flow rate in lb-moles per hour;
BC_{SRU}	=	baseline SRU flue gas baseline concentration in ppmvd at 0 % O2;
BWG	=	baseline waste gas flow in lb-moles per hour;
BNG	=	baseline natural gas flow in lb-moles per hour;
BTA	=	baseline theoretical air in lb-moles per hour;
B%EA	=	baseline percent excess air; and
BSP	=	baseline sulfur product loss in lb-moles per hour calculated based on an annual average of sulfur recovered in long tons per day for that calendar year.

3. For heaters and boilers, baseline emissions in tons per year for a particular calendar year shall be calculated as follows:

$$BE_{H\&B}\,(tpy) = [(BCO_{H\&B} \times BUO_{H\&B}) + (BCFG_{H\&B} \times BUFG_{H\&B}) + (BCNG_{H\&B} \times BUNG_{H\&B})] \times [8760/2000]$$

Where:

$BUO_{H\&B}$	=	baseline utilization rate of the heater or boiler on oil in mmBTU/hr;
$BUFG_{H\&B}$	=	baseline utilization rate of the heater or boiler on fuel gas in mmBTU/hr;
$BUNG_{H\&B}$	=	baseline utilization rate of the heater or boiler on natural gas in mmBTU/hr;

$BCO_{H\&B}$ = baseline concentration for emissions of a pollutant from the heater or boiler firing oil in lb/mmBTU;

$BCFG_{H\&B}$ = baseline concentration for emissions of a pollutant from the heater or boiler firing fuel gas in lb/mmBTU;

$BCNG_{H\&B}$ = baseline concentration for emissions of a pollutant from the heater or boiler firing natural gas in lb/mmBTU.

To determine the contribution of SO2 emissions from oil firing, the baseline emissions for SO2 only for all heaters and boilers collectively firing oil shall be calculated by the following alternative method in place of $BCO_{H\&B}$ x $BUO_{H\&B}$ in the equation above:

$$BROE = BOFR_{H\&B} \times 42 \times DO \times wt\%S \times 64/32 \times (1/2000)$$

Where:

BROE = Baseline refinery-wide SO2 emissions from oil firing in tons per year;

$BOFR_{H\&B}$ = Baseline oil firing rate in barrels per year;

DO = Baseline density of oil in pounds per gallon; and

wt%S = Baseline sulfur content of oil in weight percent sulfur.

4. For other units included within a PAL, MAP shall propose for EPA approval a calculation method consistent with the above methods in its application for the PAL.

II. Establishing the Cap. MAP shall establish the Initial Cap and each annual revision to that Cap used in any PAL submitted for approval by EPA pursuant to this Consent Decree in accordance with procedures of this Appendix.

A. Each initial Cap shall be calculated in accordance with the following equation separately for each pollutant:

$$\text{Initial Cap} = \sum_{a=1}^{o} (BE_{FCCU})_a + \sum_{b=1}^{p} (BE_{SRU})_b + \sum_{c=1}^{q} (BE_{H\&B})_c + X$$

X = for all other units MAP shall propose for EPA approval a calculation method consistent with the above methods in its application for the PAL

Where:

$(BE_{FCCU})_a$ = baseline emissions in tons per year for FCCU a within the PAL

o = the number of FCCUs within the PAL;

$(BE_{SRU})_b$ = baseline emissions in tons per year for SRU b within the PAL

p = the number of SRUs within the PAL;

$(BE_{H\&B})_c$ = baseline emissions in tons per year for heater or boiler c within the PAL; and

q = the number of heaters and boilers within the PAL.

B. Except as provided below, each Cap shall be revised annually as required by Paragraph 26.D. Each annual revision to the Cap shall be in tons per year and calculated in accordance with the equation below separately for SO2, NOx, and PM. For CO, the Initial Cap shall remain in effect for the full duration of the PAL and shall not be revised to lower it as CO limits become effective.

$$\text{Revised Cap} = \text{Prior Cap} - \Big[\sum_{d=1}^{r} (BE_{FCCU} - PE_{FCCU})_d + \sum_{e=1}^{s} (BE_{SRU} - PE_{SRU})_e + \sum_{f=1}^{t} (BE_{H\&B} - PE_{H\&B})_f + (BROE - PROE) \Big] + Y;$$

$(PE_{FCCU})_d$	=	$[BE_{FCCU}]_d$ x $[PC_{FCCU}]_d$ / $[BC_{FCCU})]_d$;
$(PE_{SRU})_e$	=	$[BE_{SRU}]_e$ x $[PC_{SRU}]_e$ / $[BC_{FSRU})]_e$;
$(PE_{H\&B})_f$	=	$[PC_{H\&B}]_f$ x $([BUO_{H\&B}]_f + [BUFG_{H\&B}]_f + [BUNG_{H\&B}]_f)$ x [8760/2000];
PROE	=	$POFR_{H\&B}$ x 42 x DO x wt%S x 64/32 x (1/2000)
Y	=	for all other units MAP shall propose for EPA approval a calcualtion method consistent with the above methods in its application for the PAL;

Where:

Prior Cap	=	the prior cap for the PAL for the preceding year in tons per year;
r	=	the number of FCCUs within the PAL for which 365-day rolling average emissions limits were established pursuant to the consent decree in the preceding calendar year;
$(PC_{FCCU})_d$	=	the 365-day rolling average emission limit established pursuant to this consent decree in ppmvd at 0% O2 for FCCU d;
s	=	the number of SRUs within the PAL for which 365-day rolling average emissions limits were established pursuant to the consent decree in the preceding calendar year;
$(PC_{SRU})_e$	=	the 365-day rolling average emission limit established pursuant to this consent decree in ppmvd at 0% O2 for SRU e;
t	=	the number of heaters and boilers within the PAL for which 365-day rolling average emissions limits were established pursuant to the consent decree in the preceding calendar year;
$(PC_{H\&B})_f$	=	the 365-day rolling average emission limit established pursuant to this consent decree in ppmvd at 0% O2 for heater or boiler f;

$POFR_{H\&B}$ = Permitted oil firing rate established pursuant to this consent decree for all heaters and boilers at the refinery in barrels per year;

DO = Maximum or permitted density of oil in pounds per gallon; and

wt%S = Maximum or permitted sulfur content of oil in weight percent sulfur.

If the permitted emission rate (PE) is higher than the baseline emission (BE) rate for particular emission unit, the term BE-PE shall be considered zero for that emissions unit for the purposes of the above summation. For the Revised SO2 Caps at the Robinson, Texas City, Detroit, Canton and St. Paul Park refineries only, the Revised Cap value produced by the equation above shall be multiplied by 1.15 to arrive at the final value of the Revised Cap, provided, however, that the Revised Cap shall never be more than the Cap for the prior year. For purposes of determining the permitted emission rate for the Catlettsburg FCCU if it is shut down as a compliance option pursuant to Paragraphs 12.D.ii. and 14.D.i., PC_{FCCU} for NOx shall be deemed equal to 20 ppmvd and PC_{FCCU} for SO2 shall be deemed equal to 25 ppmvd.

III. Determining Compliance with the Cap.

A. Each day MAP shall calculate the daily emission rate using the following equations for each emissions unit in a PAL:

1. For FCCUs, daily emissions in tons per day for a particular calendar day shall be calculated as follows:

$$DE_{FCCU} = DC_{FCCU} \text{ x } [DRF_{FCCU} + DCOBF_{FCCU}] \text{ x } 379 \text{ x } MW \text{ x } [24/2000]$$

$$DRF_{FCCU} = [(3.64 \text{ x wt \% } H_D) + (1.53 \text{ x } \{100\text{-wt \% } H_D\})] \text{ x } [DCBR]$$

$$DCOBF_{FCCU} = [(DUO_{COB}) \text{ x } (9190) + (DUFG_{COB}) \text{ x } (DF_{d\text{-}fg}) + DUNG_{COB}) \text{ x } (8710)]$$

where:

DC_{FCCU}	=	calendar daily average concentration in ppmvd at 0 % O2;
MW	=	molecular weight of the pollutant in pounds per pound-mole;
wt % H_D	=	calendar daily average weight percent hydrogen on coke as determined by either continuous measurement or daily measurements of CO2 and moisture in the FCCU flue gas;
DCBR	=	calendar daily average FCCU regenerator coke burn rate in pounds of coke per hour as determined continuously or on a daily basis by heat balance and flue gas constituents;
DUO_{COB}	=	calendar daily average utilization rate of CO boiler on oil in mmBTU/hr;
$DUFG_{COB}$	=	calendar daily average utilization rate of CO boiler on fuel gas in mmBTU/hr for that calendar day;
$DUNG_{COB}$	=	calendar daily average utilization rate of CO boiler on natural gas in mmBTU/hr for that calendar day
$DF_{d\text{-}fg}$	=	the calendar daily average flow factor on a dry basis for fuel gas and shall be calculated for that calendar day for each application using the equation in section 3.2. of Method 19 in 40 CFR Part 60 Appendix A.

2. For SRUs, calendar daily average emissions in tons per day for a particular calendar day shall be calculated as follows:

DE_{SRU}	=	DC_{SRU} x [DFRI] x MW x [24/2000]
DFRI	=	DWG + [(DNG + DTA)/1-D%EA] - DSP

where:

DFRI	=	calendar daily average incinerator flue gas flow rate in lb-moles per hour;

DC_{SRU} = calendar daily average SRU flue gas concentration in ppmvd at 0 % O2;

DWG = calendar daily average waste gas flow in lb-moles per hour;

DNG = calendar daily average natural gas flow in lb-moles per hour;

DTA = calendar daily average theoretical air in lb-moles per hour;

D%EA = calendar daily average percent excess air; and

DSP = calendar daily average sulfur product loss in lb-moles per hour calculated based on an calendar daily average of sulfur recovered in long tons per day for that calendar day.

3. For heaters and boilers, calendar daily average emissions in tons per day for a particular calendar day shall be calculated as follows:

$$DE_{H\&B}\,(tpy) = [(DCO_{H\&B} \text{ x } DUO_{H\&B}) + (DCFG_{H\&B} \text{ x } DUFG_{H\&B}) + (DCNG_{H\&B} \text{ x } DUNG_{H\&B})] \text{ x } [24/2000]$$

Where:

$DUO_{H\&B}$ = calendar daily average utilization rate of the heater or boiler on oil in mmBTU/hr;

$DUFG_{H\&B}$ = calendar daily average utilization rate of the heater or boiler on fuel gas in mmBTU/hr;

$DUNG_{H\&B}$ = calendar daily average utilization rate of the heater or boiler on natural gas in mmBTU/hr;

$DCO_{H\&B}$ = calendar daily average concentration for emissions of a pollutant from the heater or boiler firing oil in lb/mmBTU;

$DCFG_{H\&B}$ = calendar daily average concentration for emissions of a pollutant from the heater or boiler firing fuel gas in lb/mmBTU;

$DCNG_{H\&B}$ = calendar daily average concentration for emissions of a pollutant from the heater or boiler firing natural gas in lb/mmBTU.

To determine the contribution of SO2 emissions from oil firing, the daily emissions for SO2 only for all heaters and boilers collectively firing oil shall be calculated by the following alternative method in place of $DCO_{H\&B}$ x $DUO_{H\&B}$ in the equation above:

$$DROE = DOFR_{H\&B} \times 42 \times DO \times wt\%S \times 64/32 \times (1/2000)$$

Where:

DROE = Daily refinery-wide SO2 emissions from oil firing in tons per day;

$DOFR_{H\&B}$ = Daily oil firing rate in barrels per day;

DO = Daily density of oil in pounds per gallon; and

wt%S = Daily sulfur content of oil in weight percent sulfur.

4. For other units included within a PAL, MAP shall propose for EPA approval a calculation method consistent with the above methods in its application for the PAL.

C. Calculating the total daily emissions for units within the PAL. Each day, MAP shall calculate the total daily emission rate in tons per day as follows:

$$DE_{Cap} = \sum_{g=1}^{u} (DE_{FCCU})_g + \sum_{h=1}^{v} (DE_{SRU})_h + \sum_{j=1}^{w} (DE_{H\&B})_j + DROE + Z$$

Z = for all other units MAP shall propose for EPA approval a calculation method consistent with the above methods in its application for the PAL

Where:

$(DE_{FCCU})_g$ = calendar daily emissions in tons per calendar day for FCCU g within the PAL

u = the number of FCCUs within the PAL;

$(DE_{SRU})_h$ = calendar daily emissions in tons per calendar day for SRU h within the PAL

v = the number of SRUs within the PAL;

$(DE_{H\&B})_j$ = calendar daily emissions in tons per calendar day for heater or boiler j within the PAL; and

w = the number of heaters and boilers within the PAL.

D. Calculating the 365-day rolling average emission rate. Each day, MAP shall calculate the 365-day rolling average emission rate in tons per year as follows:

$$AE_{Cap} = \sum_{k=1}^{365} (DE_{Cap})_k$$

k = the preceding 365 calendar days; and

$(DE_{Cap})_k$ = the daily emission rate in tons per day for calendar day k.

APPENDIX Q

TO FIRST REVISED CONSENT DECREE

PM CEMS study at the Canton Refinery

FIRST REVISED CONSENT DECREE

Appendix Q
Project Scope and Work Plan

Project Scope/Work Plan:

At the Canton Refinery fluid catalytic cracking unit ("FCCU"), Marathon Ashland Petroleum LLC ("MAP") shall initiate a study to determine whether there is a valid, site-specific correlation between the optical density readings from the existing FCCU opacity monitor and the manual gravimetric reference method measurements of the FCCU's particulate matter ("PM") emission rate.

MAP shall submit the results from this study, including the anticipated costs for implementing the correlation, to U.S. EPA for review. In the event of establishing a valid correlation, MAP shall initiate the necessary steps to continuously monitor and record the PM mass emission rate from Canton's FCCU. In 1998, MAP and U.S. EPA estimated that the costs of undertaking the work plan described in Appendix C of the case of United States v. Ashland Inc., Civil Action No. 98-157, would be approximately $75,000. Any disputes between MAP and U.S. EPA concerning the technical validity of the correlation or the economic feasibility associated with the implementation of a valid correlation shall be resolved through the dispute resolution procedures specified in Paragraphs 66 through 74 of the First Revised Consent Decree. MAP shall summarize the PM emission data derived from this correlation in its semi-annual progress report to U.S. EPA as specified in Paragraph 33 of the First Revised Consent Decree.

The establishment of a valid correlation shall not change the statutory or regulatory basis for determining compliance with applicable particulate matter emission limitation(s) from Canton's FCCU stack as currently specified in the Title V permit for the Canton Refinery.

Procedure

1. By no later than April 30, 2006, MAP shall submit a report to U.S. EPA Region 5 that sets forth information as follows:

    a. Manual Gravimetric Particulate Matter Measurements -- PM emission concentration, diluent, and flow data acquired from a minimum of fifteen separate one-hour source tests of Canton's FCCU stack during stable operating conditions. MAP shall attempt to acquire these data over three levels of stable operation of the FCCU using as a guide Section 8.6 of 40 C.F.R. Part 60, Appendix B, Method P.S. 11. There can be a maximum of three one-hour tests in a given calendar day. MAP shall use Methods 1-4 and 5B or 5F specified in 40 C.F.R. Part 60 Appendix A to measure and calculate the particulate matter mass emission rate during these one-hour test periods. MAP may request approval from U.S. EPA Region 5 to include the paired one-hour mass emission data and optical density data acquired through testing at Canton's FCCU prior to the Date of Lodging of this First Revised Consent Decree for supplementing data used to establish the correlation, so long as those data were collected in accordance with the provisions of this paragraph;

    b. Optical Density of FCCU Emissions -- Average optical density readings during each of the fifteen separate one-hour mass emission tests from the continuous opacity monitor

("COM") on Canton's FCCU. The optical density readings shall be averaged over the same one-hour time period that was used to determine the mass emission rate from the FCCU stack during the source tests. MAP also shall submit the Performance Specification 1 certification letter from the Ohio Environmental Protection Agency ("OEPA") or U.S. EPA for the COM; the most recent audit report for that COM (OEPA or MAP can have conducted that audit); and the record of the daily zero and span drift measurements for the days that test data were acquired for this correlation study.

c. FCCU Operations Data -- Average daily coke burn rate, stack flue gas flow rate, FCCU charge rate, fresh catalyst addition rate, and total catalyst circulation rate from Canton's FCCU for each of the fifteen separate one hour emission tests. This data, which captures the variability in the operation of Canton's FCCU, shall reflect process data from the 24 hours of operation immediately preceding each of the one-hour tests.

d. MAP's analysis and conclusions (including at a minimum the following)

- Plot of mass concentration data to optical density readings to determine the correlation pursuant to the calculation and analysis procedures of 40 C.F.R. Part 60, Appendix B, Method P.S. 11, Section 12;
- Determination of whether a valid correlation exists between optical density readings and measured mass concentration from Canton's FCCU;
- Plot of measured mass emission rates to optical density readings to determine the correlation(s) pursuant to the calculation and analysis procedures of 40 C.F.R. Part 60, Appendix B, Method P.S. 11, Section 12;
- Determination of whether a valid correlation exists between optical density readings and measured mass emission rates from Canton's FCCU when the data on flow and FCCU operating conditions are factored; and
- Implementation schedule and costs to implement the correlation on a day to day basis.

2. By no later than July 31, 2006, U.S. EPA Region 5 will supply a written response to MAP regarding the report. U.S. EPA Region 5's failure to respond by July 31, 2006, will render MAP's conclusions approved. U.S. EPA Region 5 will use the data collected during the study, MAP's analysis, and all other available and relevant information to determine whether or not a valid correlation exists pursuant to the calculation and analysis procedures of 40 C.F.R. Part 60, Appendix B, Method P.S. 11, Section 12. If U.S. EPA determines that a valid correlation exists, U.S. EPA then shall determine whether or not it is economically feasible for MAP to implement the correlation.

3. If MAP and U.S. EPA Region 5 disagree about the existence of a valid correlation and/or economic feasibility, the dispute resolution procedures of the First Revised Consent Decree shall be invoked.

4. If, either by (i) agreement of MAP and U.S. EPA Region 5; or (ii) through the dispute resolution procedures of the First Revised Consent Decree, a valid correlation is deemed to exist and the implementation of this correlation is deemed to be economically feasible, then, by no later than 90 days after the agreement or the conclusion of dispute resolution (whichever applies), MAP shall complete the implementation of the necessary measures to allow the use of the correlation on a day to day basis.

5. MAP shall summarize the progress of this study along with any PM emission data subsequently derived from this correlation in its semi-annual progress report to the U.S. EPA as specified in Paragraph 33 of this First Revised Consent Decree.

APPENDIX R

TO FIRST REVISED CONSENT DECREE

Blank Table to be used for Reporting under Paragraph 33

FIRST REVISED CD
APPENDIX R

		Pollutant (eg., SO2, Nox, PM)																	
		Month 1			Month 2			Month 3			Month 4			Month 5			Month 6		
Unit ID	Emission Unit	lb/hr	ton/month	basis	lb/hr	ton/month	basis	lb/hr	ton/month	basis	lb/hr	ton/month	basis	lb/hr	ton/month	basis	lb/hr	ton/month	basis
XX-XXXX																			
	TOTAL																		